INTEGRATED RESOURCE PLAN FOR ELECTRICITY

2010
Revision 2

REPORT

DRAFT

VERSION 8
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ABBREVIATIONS

AsgiSA	Accelerated and Shared Growth Initiative for South Africa
CCGT	Closed Cycle Gas Turbine
CO_2	Carbon Dioxide
COUE	Cost of Unserved Energy
CSIR	Council for Scientific and Industrial Research
CSP	Concentrating Solar Power
DoE	Department of Energy
DSM	Demand Side Management
EEDSM	Energy Efficiency Demand Side Management
EIA	Environmental Impact Assessment
EPRI	Electric Power Research Institute
FGD	Flue Gas Desulphurisation
FBC	Fluidised Bed Combustion
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GJ	Gigajoules
GW	Gigawatt (One thousand Megawatts)
GWh	Gigawatt hour
IDTTe	Inter-Departmental Task Team
IGCC	Integrated Gasification Combined Cycle
IMC	Inter-Ministerial Committee on energy
IPP	Independent Power Producer
IRP	Integrated Resource Plan
kW	Kilowatt (One thousandth of a Megawatt)
LNG	Liquefied Natural Gas
LTMS	Long Term Mitigation Strategy
MCDM	Multi-criteria Decision Making
MTPPP	Medium Term Power Purchase Programme
MW	Megawatt
MWh	Megawatt hour
MYPD	Multi-Year Price Determination
NERSA	National Energy Regulator of South Africa; alternatively the Regulator
NOx	Nitrogen Oxide
OCGT	Open Cycle Gas Turbine
O&M	Operating and Maintenance (cost)
PF	Pulverised Fuel
PV	Present Value; alternatively Photo-Voltaic
PWR	Pressurised Water Reactor
RAB	Regulatory Asset Base
REFIT	Renewable Energy Feed-in Tariff
RTS	Return to Service
SOx	Sulphur Oxide
TW	Terawatt (One million Megawatts)
TWh	Terawatt hour

GLOSSARY

"Base-load plant" refers to energy plant or power stations that are able to produce energy at a constant, or near constant, rate, i.e. power stations with high capacity factors.

"Capacity factor" refers to the expected output of the plant over a specific time period as a ratio of the output if the plant operated at full rated capacity for the same time period.

"Cost of Unserved Energy" refers to the opportunity cost to electricity consumers (and the economy) from electricity supply interruptions.

"Demand Side" refers to the demand for, or consumption of, electricity.

"Demand Side Management" refers to interventions to reduce energy consumption.

"Discount rate" refers to the factor used in present value calculations that indicates the time value of money, thereby equating current and future costs.

"Energy efficiency" refers to the effective use of energy to produce a given output (in a production environment) or service (from a consumer point of view), i.e. a more energy-efficient technology is one that produces the same service or output with less energy input.

"Gross Domestic Product" refers to the total value added from all economic activity in the country, i.e. total value of goods and services produced.

"Integrated Resource Plan" refers to the co-ordinated schedule for generation expansion and demand-side intervention programmes, taking into consideration multiple criteria to meet electricity demand.

"Integrated Energy Plan" refers to the over-arching co-ordinated energy plan combining the constraints and capabilities of alternative energy carriers to meet the country's energy needs.

"Levelised cost of energy" refers to the discounted total cost of a technology option or project over its economic life, divided by the total discounted output from the technology option or project over that same period, i.e. the levelised cost of energy provides an indication of the discounted average cost relating to a technology option or project.

"Peaking plant" refers to energy plant or power stations that have very low capacity factors, i.e. generally produce energy for limited periods, specifically during peak demand periods, with storage that supports energy on demand.

"Present value" refers to the present worth of a stream of expenses appropriately discounted by the discount rate.

"Reserve margin" refers to the excess capacity available to serve load during the annual peak.

"Scenario" refers to a particular set of assumptions that indicate a set of future circumstances, providing a mechanism to observe outcomes from these circumstances.

"Screening curve" refers to a graph that indicates the levelised cost of technology options relative to potential capacity factors for these technologies. These can be used to screen out clearly inferior technologies from a cost perspective.

"Supply side" refers to the production, generation or supply of electricity.

EXECUTIVE SUMMARY

While long-term planning is essential, it is fraught with uncertainty. This is particularly true today, given the pace of global change on political, economic, social, technological and environmental fronts.

The biggest challenge for all long term plans is to find a sensible balance which takes into account the divergent views and expectations put forward by the different parties involved. These views fall broadly into two categories: desired/wished for outcomes, and required inputs or outputs which are subject to various constraints. Such “could be” and “must be” parameters are the interdependent variables of planning.

Scenario planning is an effective tool to find this balance. A scenario is not a plan but rather a glimpse of a future where a particular outcome or input is amplified in a modelling process in order to observe the effect this has on the other interdependent variables. The balanced scenario is created by an assessment of all scenarios to establish a balance between desired future outcomes and the realities of known constraints. The balanced scenario is the basis for the ultimate government approved risk/policy adjusted plan.

The primary objective of the Integrated Resource Plan (IRP 2010) is to determine the long-term electricity demand and detail how this demand should be met in terms of generating capacity, type, timing and cost. However, the IRP 2010 also serves as input to other planning functions, *inter alia* economic development, funding, environmental and social policy formulation. The accuracy of the IRP is improved by regular reviews and updates as and when things change or new information becomes available. For this reason, all long-term plans should be considered as indicative rather than “cast in concrete” plans.

The proposed policy-adjusted IRP 2010 aims to achieve a balance between an affordable electricity price to support a globally competitive economy, a more sustainable and efficient economy, the creation of local jobs, the demand on scarce resources such as water and the need to meet nationally appropriate emission targets in line with global commitments. It supports the development of the Southern and Central African region by stimulating the development of hydro and other power projects in Africa. This serves as a catalyst for further economic development due to increased energy security.

The IRP 2010 supports a gross domestic product (GDP) growth trajectory averaging 4,5% over the next 20 years. It requires 41346 MW of new capacity (excluding capacity required to replace decommissioned plant) in order to meet the projected demand and provide adequate reserves. It assumes at least 3420 MW of demand side management (DSM) programmes, as well as a gradual reduction in electricity intensity due to increased efficiency and a diversification to secondary and tertiary sectors in the economy. It still assumes a significant primary sector, however, built on the extraction and beneficiation of the natural resources with which the country is blessed.

The scenario evaluation process confirmed that the “Revised Balanced Scenario” represents a fair and acceptable balance considering the divergence in stakeholder expectations and key constraints and risks, including:

- Affordability
- Reducing carbon emissions
- New technology uncertainties such as costs, operability, lead time to build etc.
- Water usage
- Job creation
- Security of supply

The least-cost Base Case would provide for alternative options other than coal such as the construction of imported hydro, liquefied natural gas (LNG)-fuelled combined cycle gas turbines (CCGTs) and some fluidised bed combustion (FBC) coal to meet the demand following Kusile’s completion. However these options are constrained by the availability of fuel or the capacity to build. This results in the bulk of the demand (for base-load power) over the planning horizon being met by coal-fired power stations, with open cycle gas turbines (OCGT) providing peaking energy. This outcome is not surprising given the relatively low direct cost of coal-fired power stations and the relatively high domestic reserves of coal to meet future demand, and given that the externalities relating to coal are not included in the Base Case.

While the Base Case Scenario indicates the least-cost alternative, these costs do not include the inherent externalities involved in coal-fired electricity production, in particular greenhouse gas (GHG) emissions and the impact on the environment as well as the security of supply imperative in diversifying the national energy base.

Scenarios were developed around the targets for GHG emissions, as well as policy objectives relating to regional development and increasing demand-side interventions. These scenarios, alongside the Base Case, were assessed in terms of cost, emissions, water consumption, localisation potential and regional development objectives, as well as discounting for additional risk to the system.

The balanced scenarios (the original Balanced Scenario and the Revised Balanced Scenario) were developed from workshops with government departments considering the results of the assessment of these criteria and balancing the objectives to converge on the proposed IRP 2010.

The proposed IRP 2010 is presented in the table below as the plan that best meets the stakeholder criteria and the policy requirements of government.

In summary the plan includes:

- The continuation of Eskom's committed build programme (including the return to service of Grootvlei and Komati power stations, and the construction of Medupi (4332 MW), Kusile (4338 MW) and Ingula (1332 MW) power stations).
- The construction of the Sere power station (100 MW wind farm).
- Phase 1 of the Renewable Energy power purchase programme linked to the National Energy Regulator of South Africa (NERSA) Renewable Energy Feed-In Tariff (REFIT1) programme amounting to 1025 MW (made up from wind, concentrated solar power (CSP), landfill and small hydro options).
- Phase 1 of the Medium Term Power Purchase programme of 390 MW (made up from co-generation and own build options).
- The Open Cycle Gas Turbine (OCGT) Independent Power Producer (IPP) programme of the Department of Energy (DoE) of 1020 MW.
- A nuclear fleet strategy, commencing in 2023, contributing at least 9,6 GW by 2030. The nuclear costs included in the IRP are generic values as for the other technologies and are not intended to tie the IRP to a specific technology.
- A wind programme in addition to the REFIT1 wind capacity, commencing in 2014, of a minimum 3,8 GW.
- A solar programme in addition to the REFIT1 solar capacity, commencing in 2016, of a minimum 400 MW. This does not include solar water heating, which is included in the DSM programme (to the extent of 1617 MW).
- A renewable programme from 2020, incorporating all renewable options, inclusive of wind, concentrating solar power (CSP), solar photo-voltaic, landfill, and hydro, amongst others) of an additional 7,2 GW.
- Imported hydro options from the region totalling 3349 MW from 2020 to 2023.
- CCGT capacity, fuelled with imported LNG, totalling 1896 MW from 2019 to 2021.
- Own generation or co-generation options of 1253 MW as identified in the Medium Term Risk Assessment study.
- Up to 5 GW of generic coal-based power generation from 2027 to 2030 (in addition to Medupi and Kusile). The choice of technology could be traditional pulverised fuel or clean coal technologies. The builder of the capacity could be Eskom, South African IPPs or regional IPPs. The choice of technology will be based on current assessments of carbon capture and storage sites and the impact of climate change mitigation targets. With the commercialisation of carbon sequestration technologies, additional coal options

could become viable. However for this IRP it was assumed that such technologies are not sufficiently developed to be included. Further iterations of the IRP could revisit this.

- Up to 5750 MW of peaking OCGT. This option could also be provided by demand response programmes.
- Eskom's DSM programme as stipulated in the multi-year price determination (MYPD) application has been incorporated. The breakdown of associated technologies for DSM is included in Appendix B, indicating the expected savings from the various constituent programmes.

A number of critical assumptions were included in the development of the proposed IRP. These include:

- The development of a nuclear strategy to provide low emission base-load alternatives to coal-fired generation from 2023;
- The development of a renewable strategy to support a low carbon energy future, specifically developing local industries that support a significant rollout of wind, solar and other renewable technologies;
- The development of infrastructure to support the importation of liquefied natural gas;
- Continued investment in the maintenance and refurbishment of existing Eskom (and non-Eskom) plant to ensure generator performance at assumed levels;
- Continued investment in DSM initiatives to improve energy efficiency and delay additional capacity requirements. This includes the expected load reduction stemming from the Department of Energy's one million solar water geyser target.

	Committed build											New build options														
	RTS Capacity	Medupi	Kusile	Ingula	DOE OCGT IPP	Cogeneration, own build	Wind	CSP	Landfill, hydro	Sere	Decommissioning	Coal (PF, FBC, Imports)	Cogeneration, own build	Gas CCGT	OCGT	Import Hydro	Wind	Solar PV, CSP	Renewables (Wind, Solar CSP, Solar PV, Landfill, Biomass, etc.)	Nuclear Fleet	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%
2010	380	0	0	0	0	260	0	0	0	0	0	0	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18
2011	679	0	0	0	0	130	200	0	0	0	0	0	103	0	0	0	0	0	0	0	1112	45647	39956	494	15.67	14.74
2012	303	0	0	0	0	0	200	0	100	100	0	0	0	0	0	0	0	0	0	0	703	46350	40995	809	15.34	13.47
2013	101	722	0	333	1020	0	300	0	25	0	0	0	124	0	0	0	0	0	0	0	2625	48975	42416	1310	19.14	15.86
2014	0	722	0	999	0	0	0	100	0	0	0	0	426	0	0	0	200	0	0	0	2447	51422	43436	1966	24.00	21.85
2015	0	1444	0	0	0	0	0	100	0	0	-180	0	600	0	0	0	400	0	0	0	2364	53786	44865	2594	27.24	20.59
2016	0	722	0	0	0	0	0	0	0	0	-90	0	0	0	0	0	800	100	0	0	1532	55318	45786	3007	29.31	20.75
2017	0	722	1446	0	0	0	0	0	0	0	0	0	0	0	0	0	800	100	0	0	3068	58386	47870	3420	31.35	19.61
2018	0	0	723	0	0	0	0	0	0	0	0	0	0	0	0	0	800	100	0	0	1623	60009	49516	3420	30.18	19.17
2019	0	0	1446	0	0	0	0	0	0	0	0	0	0	474	0	0	800	100	0	0	2820	62829	51233	3420	31.41	18.08
2020	0	0	723	0	0	0	0	0	0	0	0	0	0	711	0	360	0	0	800	0	2594	65423	52719	3420	32.71	18.68
2021	0	0	0	0	0	0	0	0	0	0	-75	0	0	711	0	750	0	0	800	0	2186	67609	54326	3420	32.81	18.19
2022	0	0	0	0	0	0	0	0	0	0	-1870	0	0	0	805	1110	0	0	800	0	845	68454	55734	3420	30.85	15.67
2023	0	0	0	0	0	0	0	0	0	0	-2280	0	0	0	805	1129	0	0	800	1600	2054	70508	57097	3420	31.36	15.56
2024	0	0	0	0	0	0	0	0	0	0	-909	0	0	0	575	0	0	0	800	1600	2066	72574	58340	3420	32.14	15.73
2025	0	0	0	0	0	0	0	0	0	0	-1520	0	0	0	805	0	0	0	1400	1600	2285	74859	60150	3420	31.96	14.44
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600	1600	2200	77059	61770	3420	32.06	14.35
2027	0	0	0	0	0	0	0	0	0	0	0	750	0	0	805	0	0	0	1200	0	2755	79814	63404	3420	33.06	14.48
2028	0	0	0	0	0	0	0	0	0	0	-2850	2000	0	0	805	0	0	0	0	1600	1555	81369	64867	3420	32.42	14.29
2029	0	0	0	0	0	0	0	0	0	0	-1128	750	0	0	805	0	0	0	0	1600	2027	83396	66460	3420	32.29	14.61
2030	0	0	0	0	0	0	0	0	0	0	0	1500	0	0	345	0	0	0	0	0	1845	85241	67809	3420	32.39	15.07

1. INTRODUCTION

The Integrated Resource Plan (IRP 2010) is a long-term electricity capacity plan which defines the need for new generation capacity for the country.

This document outlines the concepts and development behind the integrated resource plan for the electricity industry in South Africa as well as the strategic objectives of the IRP, including the policy and technical parameters that drive the planning process.

A number of scenarios have been developed to inform debate on specific issues relating to future generation capacity, dealing with climate change, regional integration and the benefits of demand side initiatives, especially regarding energy efficiency. The final proposed IRP 2010 is derived from the debate arising from these scenarios.

2. PLANNING OBJECTIVES AND SCOPE OF WORK

The Energy Act of 2008 obliges the Minister of Energy to develop and publish an integrated energy plan. As electricity forms a sub-component of the energy sector, this IRP for electricity needs to be integrated into the outlook for energy. The Minister derives the power to determine and publish the IRP from the Electricity Regulations on New Generation Capacity, August 2009, which in turn are promulgated pursuant to the Electricity Regulation Act, 2006. The System Operations and Planning Division of Eskom has been mandated by the Department of Energy (DoE) to produce the integrated resource plan for electricity in consultation with the Department and the National Energy Regulator of South Africa (NERSA).

The objective of the IRP 2010 is to develop a sustainable electricity investment strategy for generation capacity and supporting infrastructure for South Africa over the next 20 years. The investment strategy includes implications arising from demand-side management (DSM) and pricing, as well as capacity provided by all generators (Eskom and independent producers).

The IRP is intended to:

- Improve the long term reliability of electricity generation through meeting adequacy criteria over and above keeping pace with economic growth and development;
- Ascertain South Africa's capacity investment needs for the medium term business planning environment;
- Consider environmental and other externality impacts and the effect of renewable energy technologies; and
- Provide the framework for Ministerial determination of new generation capacity (inclusive of the required feasibility studies) as envisaged in the New Generation Capacity regulations.

2.1. Governance

The regulations for New Generation Capacity assign governance of the IRP to different parties. The regulations state that the process for developing the IRP shall include:

a) Adoption of the planning assumptions;
b) Determination of the electricity load forecast;
c) Modelling scenarios based on the planning assumptions;
d) Determination of the base plan derived from a least-cost generation investment requirement;
e) Risk adjustment of the base plan, which shall be based on:
    i. The most probable scenarios; and
    ii. Government policy objectives for a diverse generation mix, including renewable and alternative energies, demand side management and energy efficiency; and
f) Approval and gazetting of the integrated resource plan.

While the IRP includes current policy imperatives into the planning process, the outputs can and will have an impact on further policy directions and strategies of other Ministries. This impact is particularly evident in the discussion on climate change mitigation strategies. The IRP process is a dynamic and iterative process, subject to ongoing review and update. However the long lead times required for expansion mean that vacillation on choice will lead to delays in capacity being built, with a subsequent impact on economic growth and jobs.

For the current revision of the IRP, the following forums, committees and Government initiatives have been established to govern its development:

a. The Inter-Ministerial Committee on energy (IMC);
b. The Inter-Departmental Task Team (IDTTe);
c. Work Group 2 (an IMC working group) on the IRP (WG2); and
d. The IRP Technical Task Team (IRP TTT) whose role is to advise the DoE on technical IRP matters.

Much of this governance is an interim arrangement with the IMC, due to be disbanded shortly. A long-term (permanent) governance and decision-making framework, including industry, civil society and trade unions, must be established with clear assignment of roles and responsibility. This must be accompanied by a framework to ensure allocation of build programmes to Eskom and independent power producers (IPPs).

Consultation and the IRP 2010 Development Process
The Department of Energy undertook to launch a proactive stakeholder consultation process to ensure that critical input could be sourced from a diverse constituency during the development of the plan, rather than post the publication of the plan. This process was a two-phased intervention:

- Consultation on input parameters to the IRP 2010 modelling; and
- Consultation on the Balanced Scenario and draft IRP 2010.

The final input parameter values that were used in the modelling of the scenarios were based on a consolidation of both government and broader stakeholder desired outcomes and constraints, as prescribed by legal, physical or moral limitations. The Balanced Scenario was developed based on the balancing of government policy objectives, including objectives for a diverse generation mix, renewable technologies, demand side management and energy efficiency, and sustainability.

Given the inherent uncertainty in long-term planning, the scenarios also considered sensitivities such as different demand forecasts.

2.2. Scope

The IRP covers the expansion of supply-side capacity to meet future electricity demand, including demand-side interventions to compete with supply-side options. The IRP deals only with the electricity industry, specifically the electricity supply industry, and does not integrate extensively with other energy industries or markets. Thus it is not an integrated energy plan (catering for all energy sources and uses), but deals specifically with the integration of resources for electricity production and consumption. This would form a subset of the overall Energy Plan produced by the DoE.

The IRP is developed for the period 2010 to 2030. While the load forecast is provided for 25 years (to 2034), the last four years of the expansion plan are not presented as these represent “end effects” relating to modelling concerns.

A reference plan (or base plan) is produced as an optimal plan, considering only the direct costs of all capacity options. Thereafter specific policy objectives and risk mitigation considerations are included in the planning to determine a risk-adjusted plan.

The IRP 2010 Revision 2 was developed following public participation in the inputs to the model as well as a review of the inputs and model used in determining Revision 1 (the first four years of which were promulgated in January 2010). Some of the key differences between Revision 2 and Revision 1 are:

- The expected energy consumption (and demand profile) for the next 20 years has been revised, based on the realised impact of the recent economic downturn and revised expectations based on the approved MYPD price increases;
- Generic costs for supply-side technologies have been used in Revision 2 as opposed to the Eskom-based costs in Revision 1;
- The DSM programme is not included in the demand forecast, but separately identified as a mandatory programme for the model;
- Additional information arising from the public participation was included, in particular the sugar cane fibre biomass options, future liquefied natural gas (LNG) prices, and additional scenario suggestions.

2.3. Planning parameters

Adequacy criteria

Inadequate reliability of South Africa's generation, transmission and distribution system may lead to interruptions of the supply of electricity to customers; either randomly selected or specifically selected on account of their load management contracts with the System Operator.

Reserve, redundancy and reliability standards, criteria and targets, were selected primarily to minimise the sum of the cost to the country of the energy supplied and of the cost to the customer of the energy 'unsupplied' as a result of equipment failure or system inadequacies. The economic evaluation of investments affecting the reliability of supply takes into account the cost to the customer of unsupplied energy, and its probability of occurrence.

This method can be applied in two ways: either through determining a specific reserve margin outside the expansion planning model, which is then entered as a constraint to the model; or alternatively, allowing the expansion planning model to optimise the level itself (based on the cost of unserved energy and the supply-side costs) and to determine the appropriate mix of plant to meet this optimised level.

The optimisation inherent in the IRP 2010 model determines the appropriate generation adequacy for the system, based on the cost of unserved energy (COUE). If this is correctly modelled (with an appropriate value for the COUE) the optimal expansion plan would incorporate the negative impacts of not meeting demand. This should suffice to negate the need for explicit adequacy criteria, along with appropriate sensitivity studies to accommodate uncertainties in the underlying assumptions.

The reserve margin is published as an indicator, both with and without adjustment for the capacity credits (or firm capacity) provided by variable technologies (especially wind). The COUE is set at R75/kWh, with a sensitivity test on a lower COUE of R10/kWh.

The COUE of R75/kWh is derived from the cost impact on consumers in the marginal sector (where the worst impact of supply interruptions took place). At the lower end the R10/kWh is determined from the electricity intensity (as the value of economic production for each kWh of electricity consumed to produce it).

Discount rate

The discount rate is set at a real (after inflation) rate of 8% per annum before tax. Sensitivities have been calculated at 3% and 13% using the screening curves, indicating the impact of discount rates on technology levelised costs. The screening curves are discussed further in Appendix C.

The discount rate serves as a proxy for the financing of projects. Any reduction in the discount rate (either overall or for specific technologies) implies a subsidy by government, which needs to be accommodated in the fiscus.

The 8% real discount rate reflects the rate approved by NERSA for state-owned enterprises (Eskom, Transnet).

Exchange rate
The exchange rate was used as per the Electric Power Research Institute (EPRI) report, using R7.40/USD (as at beginning January 2010).

Since the IRP deals with real values over the period of the study, exchange rate fluctuations would be inconsistent with this approach. With significant changes to the modelling inputs, allowance can be made for varying exchange rates, but no significant benefit is derived from this change.

Technical assumptions
Appendix A covers assumptions and parameters for expected energy consumption.
Appendix B covers assumptions and parameters for demand-side interventions (including energy efficiency initiatives).
Appendix C covers assumptions and parameters for supply side options (including renewable energy technologies).

2.4. Modelling

Each of the scenarios determined below (including the Base Case) has been modelled with the objective of minimising the direct costs of the expansion plan (including capital, fuel and operating costs). When certain constraints have been imposed, including emission constraints in specific scenarios, these are always constraints on the cost optimisation objective.

For modelling efficiency purposes the calendar year is converted into a load duration curve with time slices representing periods of similar demand. This mechanism is used for the expansion plan optimisation. For the robustness check in the sensitivity analysis, a full production optimisation is executed on the chronological calendar year, ensuring that the pumping cycle, amongst other considerations, is accurately reflected.

Planned outage co-ordination is modelled by allowing the system to optimise planned outages according to capacity availability. In addition, unplanned outages are modelled by adjusting the load duration curve to an effective load duration which incorporates the probability of plant failure[1]. However, for the purposes of the scenarios, which include emission limits and other output related indicators, an alternative methodology is used, since the effective load duration methodology would result in additional total generation (to meet the higher effective demand calculated from the plant failure probability). The alternative methodology uses reserve requirements on generators to emulate the additional capacity for outages, thus generator output is more realistic and emissions and other constraints relating to this output can be more accurately modelled.

3. SCENARIOS

All the scenarios were modelled based on the cost assumptions for potential supply-side projects, assumptions for demand-side interventions as well as the underlying expected demand. All known, feasible projects were included in each scenario, which included:

- Eskom and non-Eskom committed generation projects;
- IPP programmes;
- Decommissioning programmes; and
- Mandated demand-side interventions.

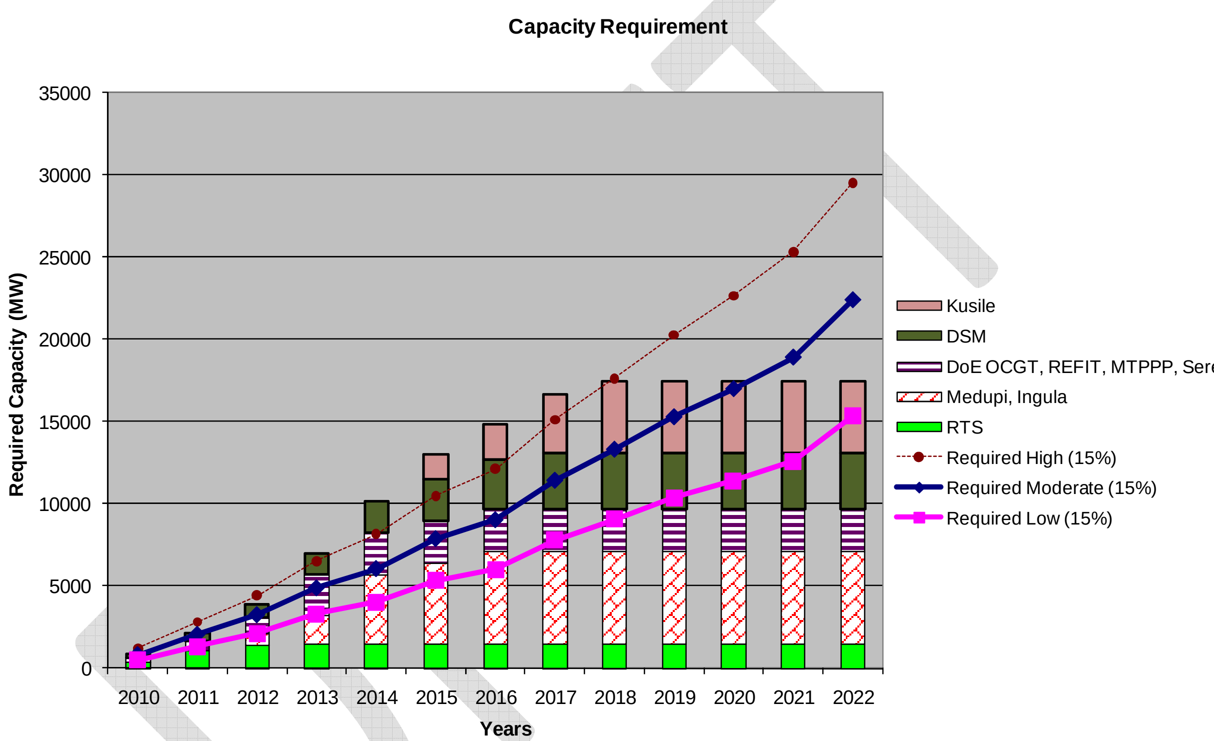
The demand forecast used is as per Appendix A with the committed DSM programme indicated in Appendix B.

Capacity requirements
Figure 1 provides a simplistic view of the capacity required in each year from 2010 to 2020 to meet three different forecasts as discussed in Appendix A. An assumed 15% reserve margin is added to

[1] In the case of Koeberg, the actual maintenance schedule determined by Eskom is incorporated as it contains the considerations for refuelling outages.

each of the three forecasts (high, moderate, low). The requirement in each case is the demand required (with reserve margin) less the existing South African generation capacity (43 895 MW), net of planned decommissioning. The projects currently under development are indicated. These include the return to service (RTS); the base-load capacity under construction at Medupi and Kusile as well as the peaking capacity under construction at Ingula; the IPP programmes represented by the DoE OCGT, the REFIT and the Medium Term Power Purchase Programme (MTPPP) programmes; and the funded Eskom DSM programme. These programmes (in various stages of commitment) fill the gap to some extent, but the graph highlights the shortfall in meeting a 15% reserve margin on the high capacity requirement after 2017, and on a moderate capacity requirement after 2020, whereas the low growth is met with existing programmes until decommissioning of existing plant requires replacement from 2022. The Kusile capacity is indicated separately to identify the requirement should this capacity not materialise.

Figure 1. System capacity requirement



It should be noted that this view is overly simplistic in that it excludes the energy constraints applicable to generators such as OCGT, pumped storage and hydro plants. The energy requirement would accelerate the need for additional capacity to a point before that reflected in this graph.

Given the existing uncertainty regarding the Eskom build programme, in particular the funding of the Kusile power station, three Base Cases were developed: Base Case 0.0 (using the current committed Eskom build); Base Case 0.1 (excluding Kusile from the build completely) and Base Case 0.2 (with a 12 month delay in Medupi and a 24 month delay in Kusile). The purpose of this was to provide information to the debate regarding the future of Kusile, especially the impact of not continuing with the programme. Many of the scenarios were also developed to allow for a case inclusive of the Kusile capacity and another case excluding that capacity.

A number of scenarios have been developed to incorporate specified uncertainties or unknowns, including possible policy objectives that are as yet unclear. The results from these scenarios were assessed to determine a risk-adjusted IRP (as distinct from the least-cost Base Case) to accommodate the policy considerations and uncertainties.

Each scenario is based on the System Operator moderate forecast, with no learning curves for technologies.

Table 1. Scenarios for the IRP

Scenario	Constraints	Kusile
Base Case 0.0	Limited regional development options No externalities (incl. carbon tax) or climate change targets	Committed
Base Case 0.1	As above	Excluded
Base Case 0.2	As above	Committed, but 24 month delay; and 12 month delay for Medupi
Emission Limit 1.0 (EM1)	Annual limit imposed on CO_2 emissions from electricity industry of 275 MT CO_2-eq	Committed
Emission Limit 1.1	As above	Excluded
Emission Limit 2.0 (EM2)	Annual limit imposed on CO_2 emissions from electricity industry of 275 MT CO_2-eq, imposed only from 2025	Committed
Emission Limit 2.1	As above	Excluded
Emission Limit 3.0 (EM3)	Annual limit imposed on CO_2 emissions from electricity industry 220 MT CO_2-eq, imposed from 2020	Committed
Emission Limit 3.1	As above	Excluded
Carbon Tax 0.0 (CT)	Imposing carbon tax as per Long Term Mitigation Strategy (LTMS) values (escalated to 2010 ZAR)	Committed
Carbon Tax 0.1	As above	Excluded
Regional Development 0.0 (RD)	Inclusion of additional regional projects as options	Committed
Regional Development 0.1	As above	Excluded
Enhanced DSM 0.0 (EDSM)	Additional DSM committed to extent of 6 TWh energy equivalent in 2015	Committed
Enhanced DSM 0.1	As above	Excluded
Balanced Scenario	Emission constraints as with EM 2.0, Coal costs at R200/ton; LNG cost at R80/GJ, Import Coal with FGD, forced in Wind earlier with a ramp-up (200 MW in 2014; 500 MW in 2015; 800 MW in 2016; 1200 MW in 2017; 1600 MW annual limit on options thereafter)	Committed, but 24 month delay; and 12 month delay for Medupi
Revised Balanced Scenario	As with Balanced Scenario, with the additional requirement of a solar programme of 100 MW in each year from 2016 to 2019 (and a delay in the REFIT solar capacity to 100 MW in each of 2014 and 2015). CCGT forced in from 2019 to 2021 to provide backup options. Additional import hydro as per the Regional Development scenario	Committed, but 24 month delay; and 12 month delay for Medupi

The detailed results for each case are provided in Appendix D. The key aspects of each scenario are discussed here.

Base Case

The Base Case (with Kusile and Medupi as per the original committed schedule) provides for imported hydro as the first base-load capacity in 2020 (after the committed programmes), followed by combined cycle gas turbines (CCGT) (fuelled by liquefied natural gas, or LNG), then imported coal and fluidised bed combustion (FBC) coal, before pulverised coal which forms the basis of all further base-load capacity. Additional peaking capacity is exclusively provided by open-cycle gas turbines (OCGT), fuelled by diesel.

CO_2 emissions continue to grow (albeit at a lower rate due to more efficient power stations replacing decommissioned older ones) to a level of 381 million tons at the end of the period (2030). Water usage drops from 336 420 million litres in 2010 to 266 721 million litres in 2030 (due to replacing older wet-cooled coal power stations with newer dry-cooled ones).

The cancellation of the Kusile project would require alternative capacity to be built in 2017, in this case FBC coal and CCGT, with additional projects brought on at least a year earlier in each case. This increases the cost to the economy from R789bn to R840bn (in present value terms), *but does not include* the net impact of the cost saving on the cancelled project and penalties relating to this cancellation. The present value costs indicated do not include capital costs for committed projects.

A delay in building Medupi and Kusile causes some projects to be brought forward, for example an FBC coal unit in 2015 and CCGT units in 2017/18, to cover the reduced capacity over the medium term, but other options are pushed further out in time as the last unit of Kusile is only commissioned by 2020. Security of supply is not dramatically impacted by the delay, as long as the identified mitigating projects can be built in the periods required.

Emission Limit 1
Imposing a limit on emissions (at 275 million tons of CO_2 throughout the period) shifts the base-load alternatives away from coal (in particular pulverised coal) to nuclear and gas. Wind capacity is also favoured to meet the energy requirements over the period, especially as the emission constraint starts to bite in 2018. As the nuclear programme is restricted in terms of its build rate (one unit every 18 months starting in 2022) wind is required to reduce emissions in the interim. CCGT provides a strong mid-merit alternative until nuclear is commissioned, especially providing higher load factors than wind, with some dispatchability. The total cost to the economy (excluding capital costs of committed projects) is R860bn, compared with R789bn for the Base Case, but with significantly lower water consumption (241 785 million litres in 2030).

The scenarios with the cancellation of Kusile allow for additional pulverised coal generation to be built later (in 2028) with more wind capacity before 2022. CCGT capacity is brought forward to fill the gap left by Kusile's cancellation.

Emission Limit 2
The emission limit is retained at 275 million tons but is only imposed from 2025. Under these conditions the nuclear and wind build is delayed (nuclear by one year, wind by five years). The other capacity is similar to the Base Case until 2022, when low carbon capacity is required to ensure that the constraint can be met in 2025. Decommissioning of older power stations (6654 MW by 2025) provides an opportunity to return to the constrained level of emissions. The cost to the economy is lower than the Emission Limit 1 scenario at R835bn with a slightly higher average annual emission of 275 million tons (as opposed to 266 million tons).

Emission Limit 3
The tighter emission limit of 220 million tons is imposed from 2020. This requires a significant amount of wind capacity (17600 MW starting in 2015) and solar capacity (11250 MW commissioned between 2017 and 2021) to meet the constraint. In total 17,6 GW of wind, 11,3 GW of solar and 9,6 GW of nuclear are built, with no coal capacity included. CCGT is constructed as a lower emission mid-merit capacity along with 6,5 GW of OCGT peakers.

The cost to the economy is significantly higher at R1250bn with much lower average annual emissions (235 million tons) and water consumption (218 970 million litres in 2030).

Carbon Tax
The carbon tax scenario includes a carbon tax at the level of that discussed in the Long Term Mitigation Strategy (LTMS) document, starting at R165/MWh in 2010 rands, escalating to R332/MWh in 2020 until the end of the period (2030) before escalating again to R995/MWh in 2040. This level of carbon tax causes a switch in generation technology to low carbon emitting technologies, in particular the nuclear fleet (starting in 2022) and wind capacity of 17,6 GW starting in 2020. The remainder is provided by imported hydro (1959 MW), OCGT (4255 MW) and CCGT (4266 MW) with some FBC coal after 2028 (1750 MW).

The cost to the economy (excluding the tax itself, which would be a transfer to the fiscus) arising from the changed generation portfolio is R852bn, with average annual emissions at 269 million tons and water consumption declining to 238 561 million litres in 2030.

Regional Development
While the Base Case only includes some import options (limited import hydro (Mozambique) and import coal (Botswana)), the regional development scenario considers all listed projects from the Imports parameter input sheet. These additional options provide good alternatives to local supply options at lower generation costs (but require additional transmission capacity to transport the energy).

Including these options brings the total cost to the economy (excluding the transmission backbone requirement for these projects) to R783bn (R6bn cheaper than the Base Case). The import coal and hydro options are preferred to local options, but imported gas is not preferred to local gas options.

Enhanced DSM
A test case scenario was run to see what the impact of additional DSM would be on the IRP. For this scenario an additional 6 TWh of DSM energy was forced by 2015. The resulting reduction in cost was R12,8bn (R789,5bn of the Base Case less R776,7bn for the Enhanced DSM scenario) on a PV basis, indicating that if a 6 TWh programme could be run for less than this cost it would be beneficial to the economy.

Balanced Scenarios
Two balanced scenarios were created considering divergent stakeholder expectations and key constraints and risks. The balanced scenarios represent the best trade-off between least-investment cost, climate change mitigation, diversity of supply, localisation and regional development. The CO_2 emission targets are similar to those in the Emissions 2 scenario.

The balanced scenarios include the Eskom committed build programme plus the MTPPP and REFIT commitments. A significant amount of wind is built, as this is the cheapest renewable energy option. Care is taken to ensure a steady and consistent build up in wind capacity in order to stimulate localisation of manufacturing and job creation. A consistent, although more modest, commitment is given to the more expensive concentrated solar option (CSP) in order to develop local experience with this technology as well as costs. The renewable energy options continue after 2020, but are not specified according to technology type at this stage. These choices will be made when there is more local knowledge and experience with both wind and solar energy. Nuclear energy comes in as a base-load option from 2023 – but because this is 13 years away, this decision does not yet have to be made. The scenario also provides for substantial diversity with gas, regional hydro, and coal options also included. In addition, allowance is made for some short to medium term co-generation and self-build options to bolster security of supply concerns.

Figure 2. Net new generation capacity (Base Case 0.0)

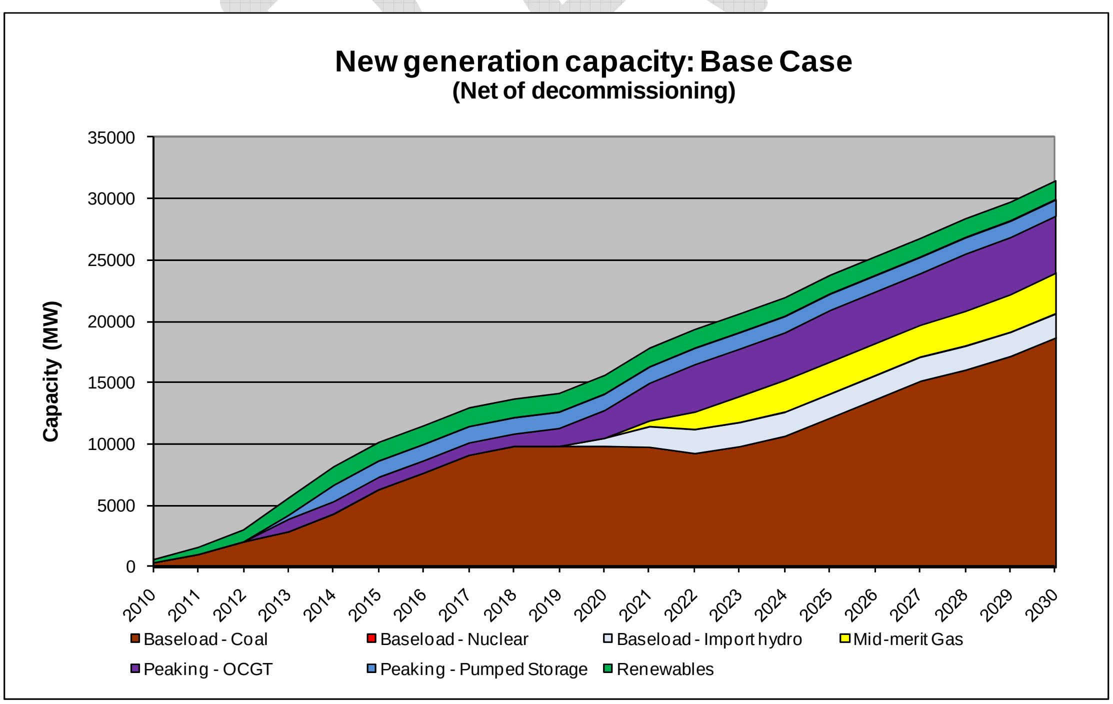
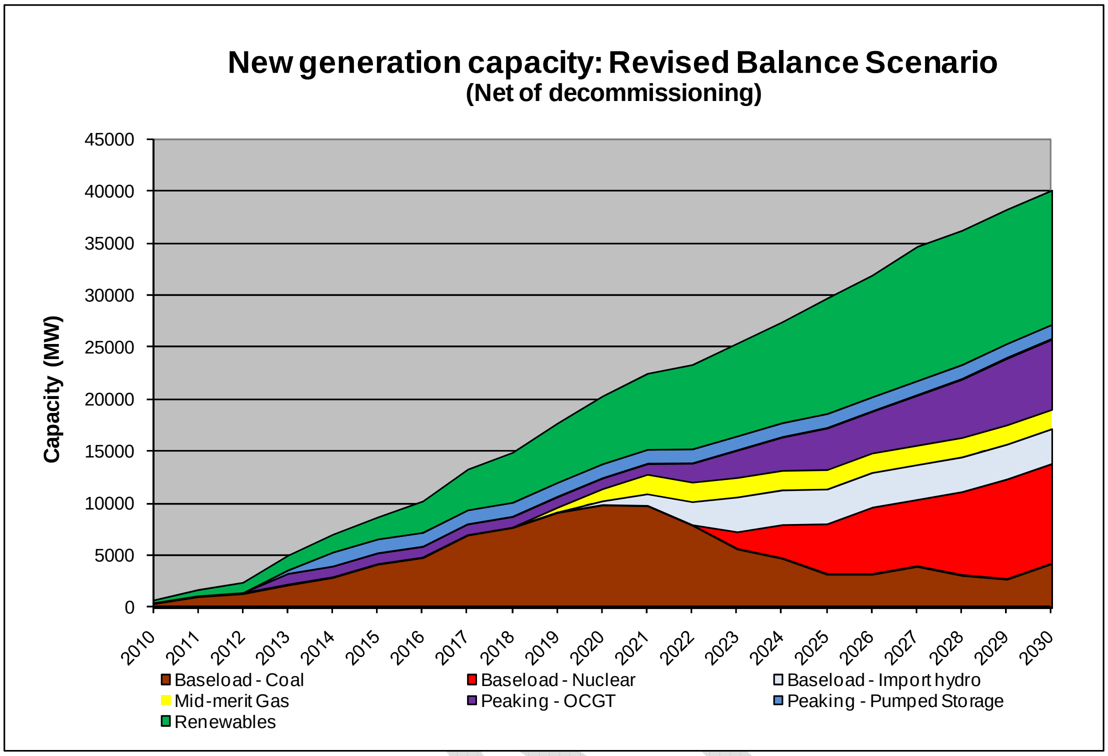


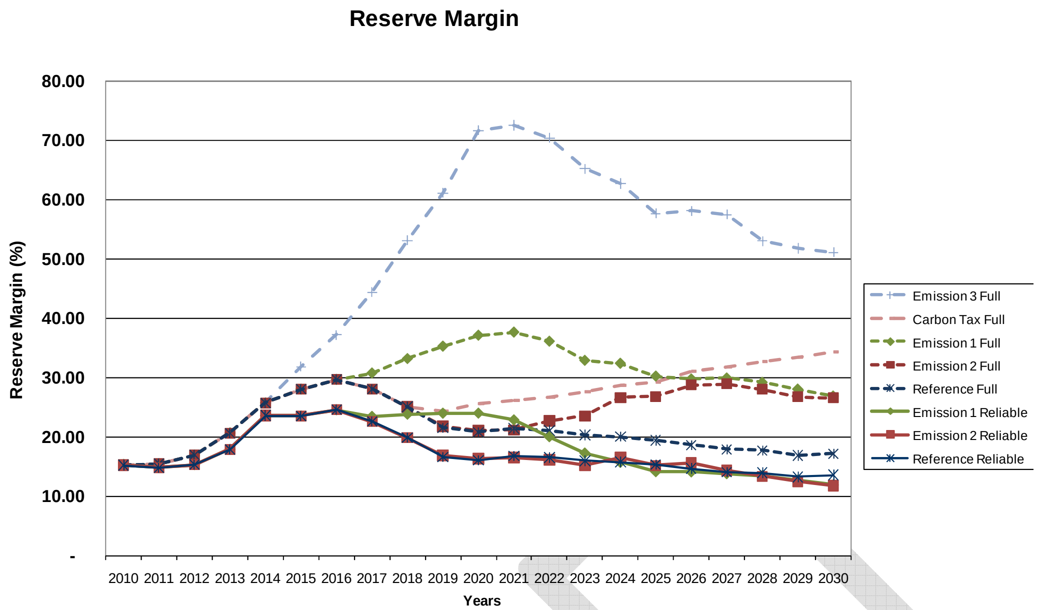
Figure 3. Net new generation capacity (Revised Balance Scenario)



Adequacy

While the reserve margin is a weak indicator of generation adequacy for the system, it provides a useful snapshot for the annual peak. In this case each scenario meets (or at least approaches) a 15% reserve margin, adjusted for capacity credits for variable generation sources. Scenarios with high penetration from variable generation sources, in particular wind generation, have significantly higher unadjusted, or full, reserve margins, due to the higher capacity required to provide an equivalent “predictable” capacity.

Figure 4. Reserve margins for scenarios

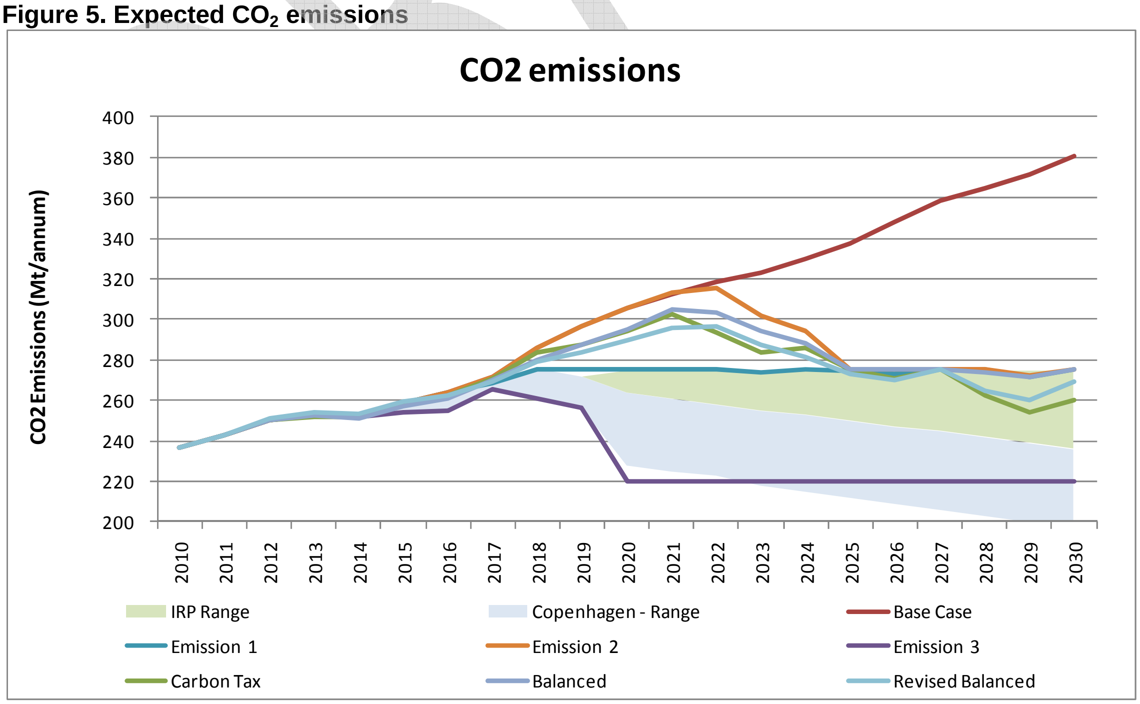


Emissions

With the imposition of specific carbon emission constraints the model ensures that the limit will be reached and coal-fired generation is adjusted to this target. This includes the possibility of limiting generation at older, less efficient power stations to the point that they may be "stranded" ahead of their expected end-of-life. This impact is indicated in the price curves below, especially in the cases where Kusile is constructed as per the Eskom build programme.

On the other hand, the carbon tax scenario imposes the tax as a cost of coal-fired generation and the emissions are an outcome of the optimisation process. Figure 5 shows how the carbon tax scenario exceeds the targets imposed in EM1.0 and EM2.0.

Figure 5. Expected CO_2 emissions



Apart from the reduction in absolute emissions in the emission constrained and carbon tax scenarios, all the scenarios also indicate an improvement in the relative emissions (or emission rates) for the electricity sector. While the Base Case has only a marginal improvement (due to the replacement of older power stations with newer, more efficient capacity) the emission constrained scenarios indicate a significant drop in the relative emissions of the electricity sector, as reflected in
Figure 6.

Figure 6. Expected CO_2 emission rates

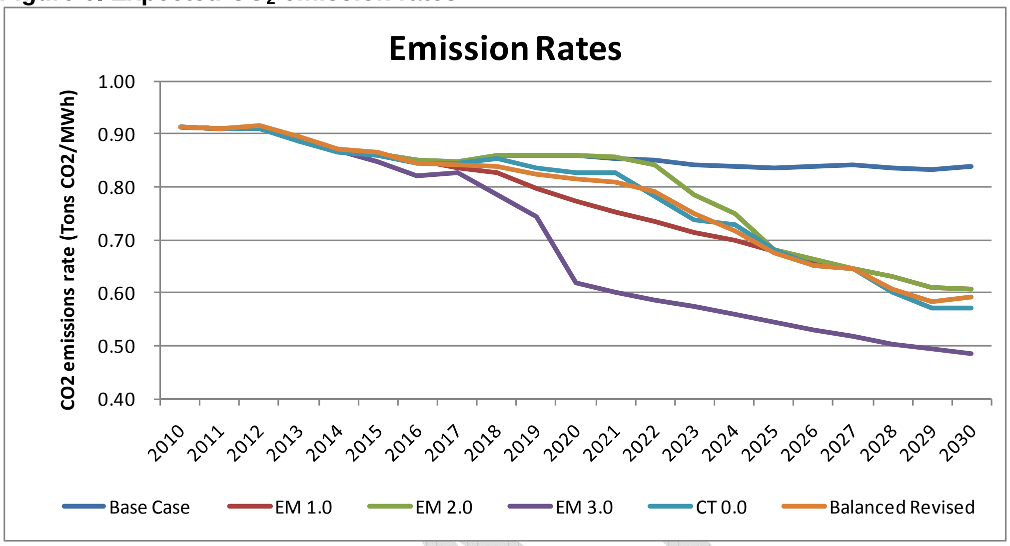
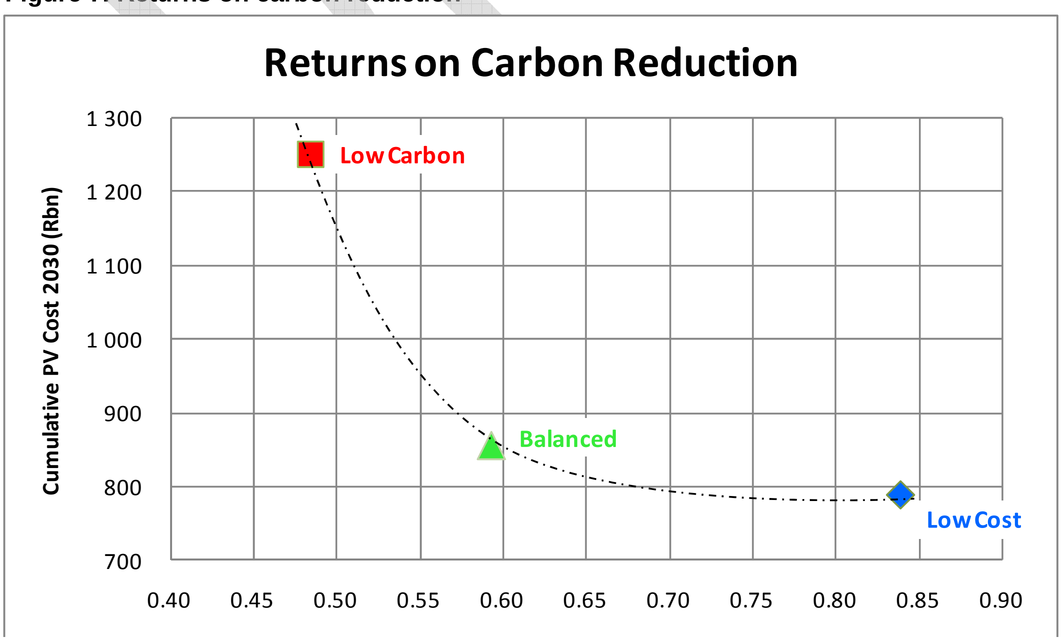


Figure 7 indicates the trade-off between the total cost of a scenario portfolio and the emissions relating to that portfolio. The “low cost” scenario (Base Case) has a high emission rate (of 0,84 CO_2 tons/MWh) but has a low direct cost of R789bn. The other extreme of the “low carbon” scenario (Emission 3) provides a much lower emission rate (of 0,48 CO_2 tons/MWh) but the total direct cost increases to R1250bn. The Revised Balanced Scenario, as a balance between the two extremes, provides an emission rate of 0,59 CO_2 tons/MWh at a cost of R856bn.

This result suggests that there is a diminishing marginal return for each decrease in the emission rate, since the Revised Balanced Scenario is able to reduce the emission rate at a smaller increase in cost, but the increase in cost from the Revised Balanced Scenario to Emission 3 is significant at only a marginal improvement in emission rate.

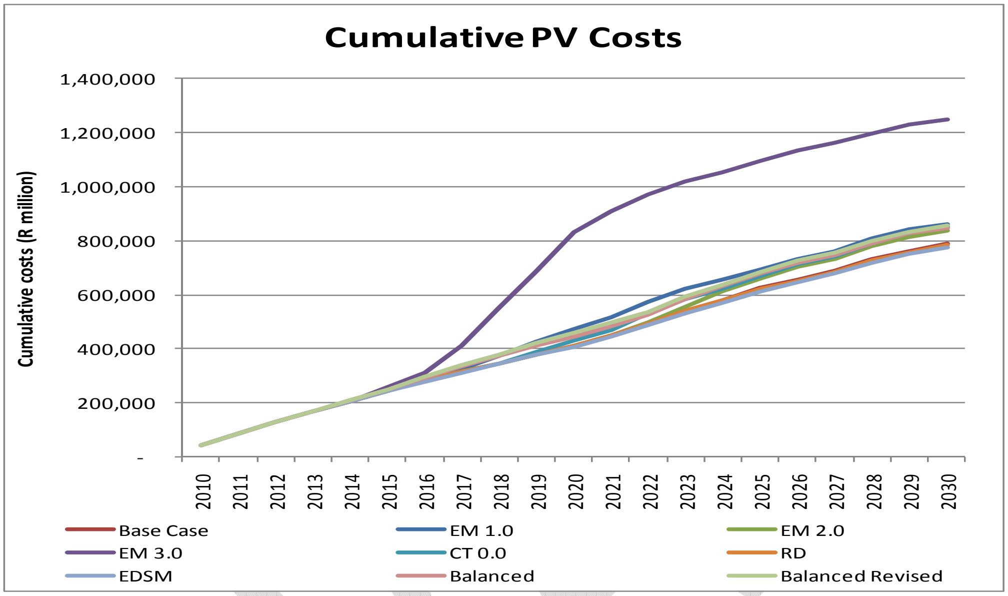
Figure 7. Returns on carbon reduction



Costs
The costs of each scenario are calculated by summing the total capital, operating and maintenance (O&M) and fuel costs for all options and then discounting these to determine the total Present Value (PV) cost for the scenario. The discount rate of 8% is applied to the present value calculation. The capital costs of the committed plant (in particular Medupi, Kusile and Ingula) are not included in the calculation as these are common across all scenarios.

The cumulative present value cost is shown in Figure 8, highlighting the large disparity between the Emission 3 scenario and the other scenarios.

Figure 8. Cumulative PV costs for each scenario



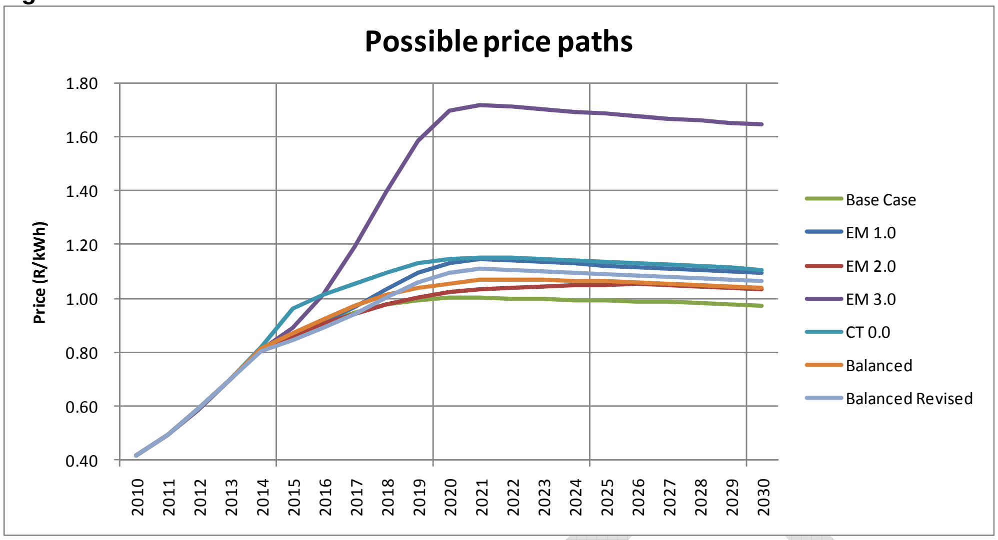
Price Curves
An alternative expression of the cost associated with each scenario is the price impact on consumers resulting from the expansion plan indicated by the scenario.

Price curves are calculated using the regulatory pricing rules as summarised in the Electricity Regulation Act (Act 4 of 2006) that allows for electricity prices to recover the full efficiently incurred cost plus a reasonable return. The annual costs in the calculations are based on the MYPD2 submission to NERSA, which is a public document, with inflationary escalation of cost buckets after the first five year period. A reasonable return was estimated using the NERSA determined cost of capital of 8.17% per annum and with the capital expenditure of the industry adjusted by the results of the IRP scenario being priced.

It is important to note that the IRP optimises the expansion plan using levelised cost calculations, while the pricing rules are different. The pricing rules allow for Operating and Maintenance (O&M) costs to be included in revenue requirements for the year they are expended, with capital expenses recovered through depreciation over 25 years after the date of commissioning for the capital portion. The financing cost is recovered by the return calculation at the real cost of capital from date of expense, allowing Work under Construction to earn a return even if no depreciation is allowed.

The price curve thus allows the MYPD2 price path of 25% nominal increases until 2012/13, which is called “2012” in this exercise because the calendar year 2012 and the financial year 2012/13 overlap by 75% and 2012 is the best approximation. After 2012 the price curve is allowed to return to the pricing rules curve with no further intervention. See curves below for the Base Case and three scenarios. The prices are shown in real 2010 rand per kWh.
Appendix F contains a more detailed explanation of the pricing model with important sensitivities.

Figure 9. Price curve for scenarios



Capital spending, operating costs and primary energy costs have been adjusted to reflect the different generation expansion plans in the future years, to calculate the price curves for the scenarios. This was achieved by assuming that the Base Case capex, primary energy and O&M costs correspond with the MYPD2 submission, and then adding the differences to the model for other scenarios, to give a relative difference which is reflected in the price curves above.

Thus the absolute price levels are less important than the difference in the price curves for various scenarios. In the above graph, the emission constrained scenario would have a price premium above the other scenarios after 2020.

The carbon tax price curve does not include the cost of the actual tax itself, only the impact of the generation choices driven by the carbon tax. This is for the benefit of comparison with the other scenarios.

4. CRITERIA

A methodology has been developed to deal with identifying the key criteria from stakeholders against which to weigh the results of the scenarios. The criteria apply to each scenario in order to provide additional inputs to the debate regarding the preferred IRP. While the scenarios are not intended as implementable plans in themselves, they provide an indication of the impact of specific policy choices. The scoring for the scenarios, based on the criteria and the evaluation thereof, is not intended to provide a definitive preferred plan from the scenario but to indicate preferences.

Once the scoring has been completed, it is expected that the benefits and costs of each scenario are discussed to drive the determination of the preferred expansion plan as the basis of the proposed IRP 2010.

A set of criteria were proposed and discussed at a series of inter-departmental workshops against which to assess a number of key parameters identified. These include:

a) Water

The usage of water is quantified for each technology, according to the independent EPRI report and information from existing Eskom plant. The cost of water for existing plant and approved future plant is known and quantified. For plant that is recommended to be built in the proposed IRP 2010 only the usage of water is quantified, given that the location of the plant is not known at this stage of the IRP.

b) Cost

Each scenario involves the construction of new generation capacity over the study period. For the current and approved projects the costs from the existing owner (Eskom, municipality or private supplier) is used. For potential new projects the approved data set of option costs will be used. The criteria applied for this dimension should cover the direct costs associated with new generation capacity built under each scenario (including capital, operating and fuel costs) as well as existing plant (but excluding capital costs for committed plant) and summed to determine the total cost of the plan. This will be discounted to determine the present value of the plan and used as a comparator between the different scenarios.

An alternative approach is to look at the future electricity price curves required to meet the generation costs incurred by the scenario portfolio. This model, similar to that applied in the Eskom MYPD decision by NERSA, provides an indicator of future costs to consumers for the electricity industry from each scenario portfolio.

c) Climate change mitigation

The Department of Environmental Affairs "Long Term Mitigation Strategy" (LTMS) provides guidance on the extent to which greenhouse gas (GHG) emissions should be restricted over time. For the purposes of the IRP the GHG emissions from existing and planned generation capacity can be quantified in the model and compared between scenarios. While certain scenarios may impose a specific limit to emissions, this criterion compares the actual emissions between all scenarios.

d) Portfolio risk or uncertainty

An approach has been developed to identify and model the risks associated with each of the scenario portfolios. There are different dimensions or sources of risk between the scenario portfolios, including (but not limited to):

- The validity of the cost assumptions for each technology;
- The validity of the lead time assumptions for each technology;
- The maturity of each technology;
- The security of fuel supplies for each technology; and
- Operational risks associated with each technology (including secondary life cycle effects), such as waste management, pollution and contamination.

Ideally these risks would carry cost elements which would enable incorporation into the IRP optimisation (through monetisation of the risk elements). However given the time constraints and dearth of data to support this process, this is not feasible at present. The second best approach would be to identify a probability distribution associated with the risks, use the standard deviation as a measure of risk, and apply these across the identified dimensions. While this can be done for some of the risk dimensions, there is again a lack of information and time to produce such measures for every dimension. The third approach is to apply subjective expert judgement to each technology for every dimension and derive a risk factor for each technology (and consequently a capacity weighting for each scenario portfolio). This methodology was used for the IRP 2010, with the resulting risk factor compared between the different scenarios.

e) Localisation benefit

A rating has been given to each scenario portfolio to indicate the extent to which this portfolio supports localisation of specific technologies and supporting industries. It is expected that the earlier a technology construction programme is triggered, and the more steadily such technology capacity is added, the higher the potential to localise the technology industry. Thus a wind industry is supported by a regular build profile, starting earlier, and consequently a portfolio that incorporates such a build profile would have a higher score in this criterion. The application is however subjective.

f) Regional development

Workshops with government departments indicated that this is an important criterion for the portfolios and that those portfolios that support increased import from regional options should receive a higher score. Thus the portfolio with the higher percentage of imports (to the total capacity) scores higher on the regional development criterion. Technically speaking the total capacity is replaced in this calculation by the demand that must be met, so as not to penalise portfolios that build significant wind (which requires more capacity for each unit of demand due to the capacity credits applied to wind).

For the first three criteria (emissions, cost of plan and water) and the regional development criterion the measurement is provided by the optimisation results. The average domestic emissions figure is determined based on the emission contribution of each of the proposed projects and its expected output in each year. Similarly the cost of the plan is determined based on the capital, operating and fuel costs of each project (discounted to 2010 rands), but specifically excludes the capital costs associated with existing power stations and the committed Eskom build. The water criterion is measured by summating the water requirements for the scenario portfolio for the entire study period.

The uncertainty factor criterion is measured using uncertainty factors for each technology, which is then applied based on the relative capacity of each technology in the portfolio. The localisation criterion is based on a subjective score applied to the portfolios based on their perceived potential for localisation.

RATING THE SCENARIOS

Each of the scenarios provides the same reliability, since the model optimises between the cost of new generation and unserved energy. Thus security of supply is not treated as a criterion.

The criteria and associated metrics provide a framework in which the balanced scenario can be assessed for “goodness of fit”. The principle is to achieve the best fit considering the divergent stakeholders’ objectives. The table below contains the criteria metric values for each of the scenarios.

Table 2. Criteria metric scores for each scenario

Scenario	Av. annual CO_2 emissions (million tons)	Price path peak (cents/kWh)	Av. water consumption (million litres)	Uncertainty factor	Localisation potential	Regional development (% capacity imports in 2030)
Base Case 0.0	303	100	327	6.87	2	6.87
Emission 1.0	266	114	310	6.12	4	6.87
Emission 2.0	276	105	319	6.12	4	6.87
Emission 3.0	236	172	283	5.21	4	3.85
Carbon Tax 0.0	269	115	316	5.34	4	5.1
Regional Development 0.0	301	101	326	6.99	2	10.4
Enhanced DSM	299	104	324	6.86	2	6.87
Balanced	272	107	318	6.05	6	4.68
Revised Balance	271	111	318	6.11	8	8.63

SCORING THE SCENARIOS

Using a rigorous multi-criteria decision making framework (MCDF) it is possible to describe, numerate and score the preferences and values of the stakeholders with respect to each of the criteria. This provides a foundation to assist in choosing a single portfolio as the preferred option. In addition it is possible to identify next-best alternates that can undergo additional stress testing to incorporate concerns regarding robustness to sensitivities.

An important step in the MCDF process is to determine weightings for each of the criterion. This provides the mechanism to score the scenario portfolios across the different criteria. Applying the agreed weighting for each criterion and value function returned the results contained in the table below.

Table 3. Score for each criteria

Plans	CO_2 emissions	Price	Water	Uncertainty	Localisation potential	Regional development	TOTAL
Base Case 0.0	-	21.74	-	2.73	-	6.08	30.54
Emission 1.0	12.41	18.61	5.24	16.14	6.47	6.08	64.94
Emission 2.0	9.43	20.61	2.53	16.14	6.47	6.08	61.25
Emission 3.0	21.74	-	10.87	19.57	6.47	-	58.65
Carbon Tax 0.0	11.50	18.41	3.50	19.26	6.47	2.77	61.91
Region Development 0.0	0.67	21.53	0.37	-	-	10.87	33.44
Enhanced DSM	1.54	20.85	0.94	3.04	-	6.08	32.45
Balanced	10.46	20.24	2.74	16.71	11.02	1.85	63.01
Revised Balance	11.01	19.33	2.92	16.32	15.22	8.85	**73.66**
Swing Weighting (/100)	21.74	21.74	10.87	19.57	15.22	10.87	100.00

The MCDF scores clearly demonstrate the extent to which the Revised Balanced Scenario" represents a fair and acceptable balance across the key criteria. The MCDF also serves as a basis for debate on policy choices.

5. RECOMMENDED EXPANSION PLAN

The balanced scenarios (the original Balanced Scenario and the Revised Balanced scenario) were developed from workshops with government departments considering the results of all scenarios and the MCDF analysis.

The initial balanced scenario was based on the Emission 2 scenario which combined the interests of affordability (or least-cost) with an emission target that complied with LTMS requirements. It was decided, however, that the wind build programme started too late and was not sufficient to ensure a local industry to support this. Thus the wind programme was forced to start in 2014 (following the initial outlays from the renewable feed-in mechanism) at a steady construction for each year. In addition, the build programme for Eskom's new coal-fired power stations was delayed – by 12 months for Medupi and by 24 months for Kusile. Costs for future coal were decreased from R300 a ton to R200 a ton, while LNG prices were increased to R80/GJ. Import coal costs were changed from the generic costs of pulverised fuel without flue gas desulphurisation (FGD) to those inclusive of FGD.

Following discussions with government stakeholders it was decided firstly, that the emissions from import coal should be excluded from domestic emissions accounting, and secondly, that a solar build programme was required alongside wind at a lower level initially considering the fact that this technology is relatively new and still evolving. The current solar programme (as part of the renewable feed-in mechanism) was moved one year later to lay the foundation for this new programme which will continue at 100 MW for each year. After 2020 the renewable programme continues as a proxy for either wind, solar or other renewable technologies which are viable at that point. Additional regional options were included as per the Regional Development scenario, and some CCGT capacity was forced to allow for a domestic contingency for import and renewable options.

Table 4. Proposed IRP (Revised Balance Scenario)

	Committed build											New build options														
	RTS Capacity	Medupi	Kusile	Ingula	DOE OCGT IPP	Cogeneration, own build	Wind	CSP	Landfill, hydro	Sere	Decommissioning	Coal (PF, FBC, Imports)	Cogeneration, own build	Gas CCGT	OCGT	Import Hydro	Wind	Solar PV, CSP	Renewables (Wind, Solar CSP, Solar PV, Landfill, Biomass, etc.)	Nuclear Fleet	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%
2010	380	0	0	0	0	260	0	0	0	0	0	0	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18
2011	679	0	0	0	0	130	200	0	0	0	0	0	103	0	0	0	0	0	0	0	1112	45647	39956	494	15.67	14.74
2012	303	0	0	0	0	0	200	0	100	100	0	0	0	0	0	0	0	0	0	0	703	46350	40995	809	15.34	13.47
2013	101	722	0	333	1020	0	300	0	25	0	0	0	124	0	0	0	0	0	0	0	2625	48975	42416	1310	19.14	15.86
2014	0	722	0	999	0	0	0	100	0	0	0	0	426	0	0	0	200	0	0	0	2447	51422	43436	1966	24.00	21.85
2015	0	1444	0	0	0	0	0	100	0	0	-180	0	600	0	0	0	400	0	0	0	2364	53786	44865	2594	27.24	20.59
2016	0	722	0	0	0	0	0	0	0	0	-90	0	0	0	0	0	800	100	0	0	1532	55318	45786	3007	29.31	20.75
2017	0	722	1446	0	0	0	0	0	0	0	0	0	0	0	0	0	800	100	0	0	3068	58386	47870	3420	31.35	19.61
2018	0	0	723	0	0	0	0	0	0	0	0	0	0	0	0	0	800	100	0	0	1623	60009	49516	3420	30.18	19.17
2019	0	0	1446	0	0	0	0	0	0	0	0	0	0	474	0	0	800	100	0	0	2820	62829	51233	3420	31.41	18.08
2020	0	0	723	0	0	0	0	0	0	0	0	0	0	711	0	360	0	0	800	0	2594	65423	52719	3420	32.71	18.68
2021	0	0	0	0	0	0	0	0	0	0	-75	0	0	711	0	750	0	0	800	0	2186	67609	54326	3420	32.81	18.19
2022	0	0	0	0	0	0	0	0	0	0	-1870	0	0	0	805	1110	0	0	800	0	845	68454	55734	3420	30.85	15.67
2023	0	0	0	0	0	0	0	0	0	0	-2280	0	0	0	805	1129	0	0	800	1600	2054	70508	57097	3420	31.36	15.56
2024	0	0	0	0	0	0	0	0	0	0	-909	0	0	0	575	0	0	0	800	1600	2066	72574	58340	3420	32.14	15.73
2025	0	0	0	0	0	0	0	0	0	0	-1520	0	0	0	805	0	0	0	1400	1600	2285	74859	60150	3420	31.96	14.44
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600	1600	2200	77059	61770	3420	32.06	14.35
2027	0	0	0	0	0	0	0	0	0	0	0	750	0	0	805	0	0	0	1200	0	2755	79814	63404	3420	33.06	14.48
2028	0	0	0	0	0	0	0	0	0	0	-2850	2000	0	0	805	0	0	0	0	1600	1555	81369	64867	3420	32.42	14.29
2029	0	0	0	0	0	0	0	0	0	0	-1128	750	0	0	805	0	0	0	0	1600	2027	83396	66460	3420	32.29	14.61
2030	0	0	0	0	0	0	0	0	0	0	0	1500	0	0	345	0	0	0	0	0	1845	85241	67809	3420	32.39	15.07

The MCDF process confirmed that this Revised Balanced Scenario represents an appropriate balance between the different stakeholder expectations considering a number of key constraints and risks, for example:

- Affordability/Funding availability;
- Reducing carbon emissions;
- New technology uncertainties such costs, operability, lead time to build etc;
- Water usage;
- Localisation and job creation;
- Southern African regional development and integration; and
- Security of supply.

Another consideration included in the Revised Balanced Scenario is the support for the development of a local industry for renewable technologies, in particular wind and solar. By bringing the construction programme for these technologies forward and maintaining a stable roll-out programme, an opportunity is provided for localisation, not only in the construction of the equipment, but in the development of skills to support the renewable programme. By not specifically categorising the renewable technologies after 2020 a window is provided for government to direct alternative renewable technology development to meet government objectives.

The total wind capacity added by 2019 is 4500 MW (inclusive of REFIT1 wind), solar capacity by 2019 is 600 MW, and the total renewable capacity added from 2019 to 2030 is 7200 MW. By forcing the earlier adoption of renewable technologies the country is able to achieve a lower GHG emission peak (296 million tons in 2022, as opposed to 315 million tons in the Emission 2 scenario) at only a marginal increase in cost to the economy.

The Revised Balanced Scenario provides ample opportunity for private investment in electricity generation from the renewable programmes to the CCGT and regional options. The decision as to who builds this capacity must still be made as part of the feasibility assessment after the finalisation of the IRP 2010.

As part of the medium term business mitigation strategy a number of own generation or co-generation options have been identified before 2017. These options have been included in the Revised Balanced Scenario as additional capacity forced in as per the medium-term schedule, in order to maintain some continuity between the plans. However these options have not been included in the calculations on water, prices or emissions.

The Revised Balanced Scenario follows the original decision that transmission infrastructure would not be included in the cost determination for different projects. However it is clear that the regional options are significantly impacted by the transmission infrastructure required to transport the power to South Africa. While there are debates regarding the actual costs for this infrastructure and what proportion would be met by domestic consumers, it is evident that options further from South Africa's borders should be penalised relative to closer options. In this regard, the import hydro options identified in the Balanced Revised Scenario could end up being more expensive than import coal options which are not built in this scenario. Thus it is possible that the latter option should be favoured over the other regional projects purely on the basis of transmission infrastructure costs, and because South Africa is not penalised by carbon emissions as these do not count toward the domestic target. This would require a modification to the scenario (with regional hydro being delayed accordingly). There is potential for additional import hydro but these projects have not been identified with sufficient costs or capacity to include. Future iterations of the IRP should include these options as better information becomes available.

6. RISKS AND UNCERTAINTIES

6.1. Sensitivity studies

Even with the policy and growth uncertainties catered for to some extent in the scenarios listed above, there are a number of other uncertainties that need to be considered. The models have been tested against changes in the underlying assumptions regarding the following, in particular:

a) Changes in the energy forecast
Since all the scenarios were modelled on the moderate forecast, a test was carried out on the high and low forecasts produced by the System Operator (see Appendix A). The impact of the high forecast is shown in Table 35 in Appendix D. The higher forecast results in the earlier commissioning of the options chosen in the Base Case where possible. A total of 28,5 GW of new pulverised coal is required (as opposed to 16,5 GW in the Base Case with the moderate forecast).

   The low forecast allows for a delay in new capacity until 2022 and a significantly lower new coal capacity requirement (to 5,2 GW by 2030). The details for this case are shown in Table 36 in Appendix D.

b) Uncertain and prolonged lead times for building new plant, in particular:
   - A twelve month delay in commissioning of Medupi, and a 24 month delay in the commissioning of Kusile.

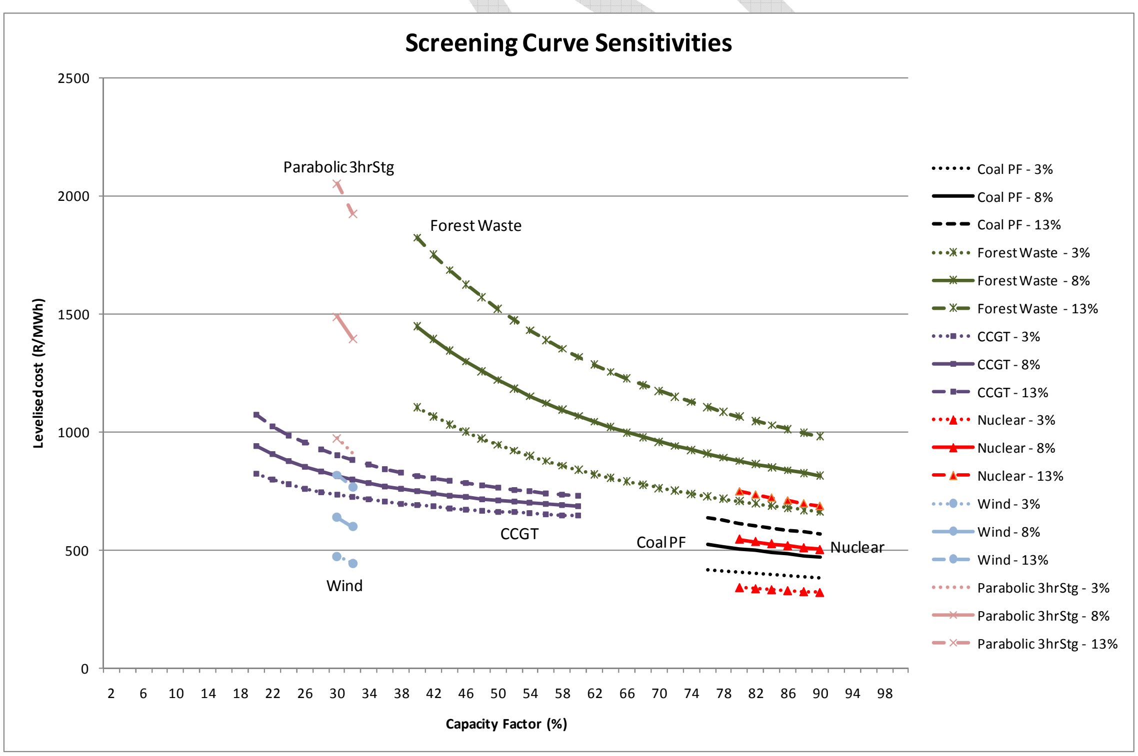
This sensitivity has been determined for the Base Case (see Table 19 in Appendix D). The clearest impact of the delay in the Eskom build programme is the lower reserve margins from 2013 to 2018 and the bringing forward of some CCGT capacity in 2018.

- The cancellation of the Kusile project.
  The result for the Base Case is captured in Table 18 in Appendix D. For the purposes of debate each scenario has also been developed with a case excluding the Kusile project.

c) The impact of a lower assumed cost of unserved energy (at R10/kWh)
This sensitivity is included in Table 34 in Appendix D. The decrease in the cost of unserved energy tilts the balance in favour of less supply-side capacity (a net new build of 29403 MW as opposed to 31878 MW in the equivalent Base Case), with an increase in unserved energy over the period, especially after the committed programme has been completed. The first new capacity required is only in 2020, a year later than in the equivalent Base Case.

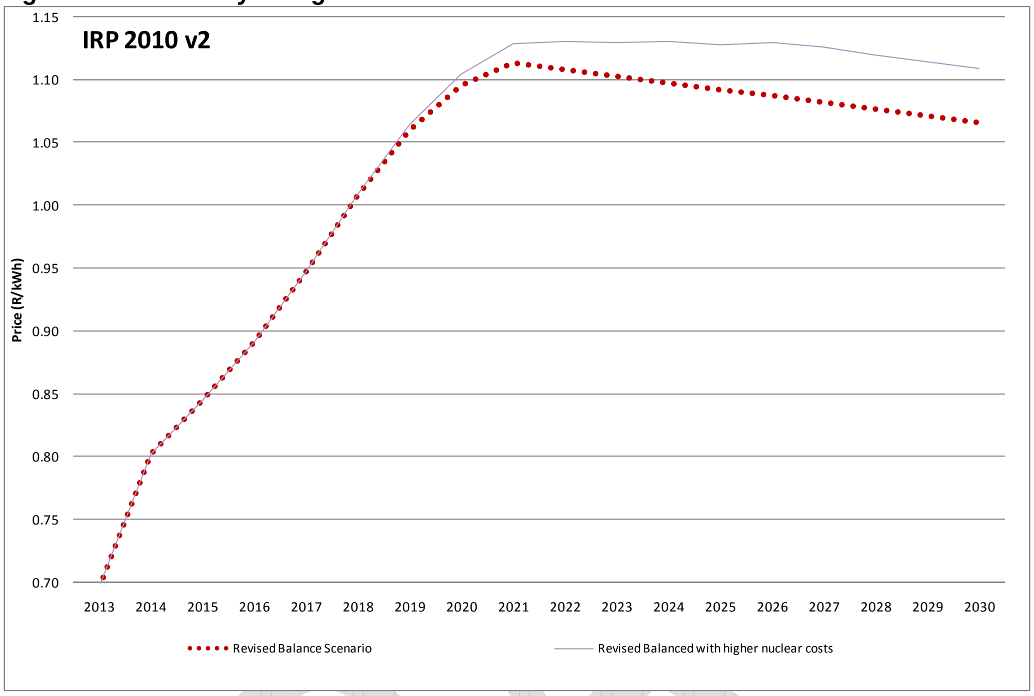
d) Discount rates
Screening curves have been developed based on the cost assumptions for each technology option, indicating the variation in levelised cost for each option based on different assumed capacity factors. These curves are also useful in testing sensitivity to other variables, in particular the impact of a higher or lower discount rate. Figure 10 indicates the impact of the choice of discount rate on the levelised cost for different technologies. Clearly technologies with a higher component of capital costs (relative to other costs) are more impacted by the choice of discount rate, for example the parabolic trough concentrated solar, wind and nuclear. In particular it is noteworthy that at an 8% discount rate pulverised coal is cheaper than nuclear for full lifecycle costs, whereas at a 3% discount rate nuclear is cheaper than pulverised coal.

Figure 10. Sensitivity on levelised costs



e) Cost of technologies
The assumed costs for nuclear capacity have elicited much debate. There is a strong probability that the costs could be higher than those assumed. The impact of this higher cost is indicated in Figure 11 which shows the higher tariff arising from an increase in capital costs of 40%.

Figure 11. Sensitivity of higher nuclear costs



6.2. *Key risks in the IRP*

The proposed IRP 2010 envisages a dramatic transition from a traditional coal-based electricity industry toward a low carbon environment. This transition carries some risks for the operations of the integrated power system, especially the introduction of variable generation technologies such as wind. The supporting infrastructure, in the form of transmission and distribution networks, and water infrastructure, amongst others, will also be impacted, especially after decommissioned coal power stations are replaced by nuclear and renewable resources which are geographically positioned away from the traditional generation sources in Mpumalanga.

However the improved diversification from reliance on coal toward numerous fuel sources reduces the inherent risk in the electricity sector.

While the risk factor criterion provides a mechanism to evaluate the potential plans for the inherent risks of each plan, it is worth highlighting the risks to provide focus for possible mitigation:

1. Execution of the energy efficiency demand side management (EEDSM) programme
   i. Either through funded Eskom programme, or
   ii. Standard offer, or
   iii. Alternative mechanisms;

2. Execution of the Eskom build programme – highlighted in sensitivities above (dependent on the funding of Kusile, while ensuring no significant slippage in Medupi and Ingula timelines);

3. Liquefied natural gas infrastructure, timelines and costs;

4. Practical execution of wind capacity expansion at the assumed rate in the IRP

   - Supporting infrastructure would be required to make the wind build rate possible, particularly in terms of sufficient equipment to hoist the wind masts across the country;

5. Impact of wind on system operations and grid stability, including the possibility of additional storage to provide back-up supply

   - The IRP 2010 assumed that the wind load factor provides a sufficient proxy for the capacity credit or firm capacity provided by wind. However, experience from other countries, in particular Germany, indicates that at higher wind penetrations the capacity credit from wind is reduced. Initial suggestions are that this should be 25% in winter and 21% in summer (as opposed to the assumed 33%), but studies are continuing to provide further input on this. Critically for the IRP results however, it is possible that the reserve margin indicated is over-stated by using the load factor as the capacity contribution from wind;

6. Practicality of the nuclear fleet build programme, including funding concerns; and

7. Realisation of the expected demand forecast

   - The demand forecast includes an assumption on the changing energy intensity of the economy. If the industrial policy is successful in promoting the regeneration of the industrial base it is possible that the decline in energy intensity may be much slower than that suggested.

   - The lack of distribution and reticulation infrastructure investment over the past decade may have constrained current consumption patterns which, with possible investment in the future, could increase the total demand for electricity beyond that anticipated. Similarly network expansion could release unrealised or "suppressed" demand and increase total demand on the system.

Another approach to these risks is to consider the critical decision points for the relevant technologies and the impact on the plan if these decisions are not made.

Table 5. Mitigation actions for IRP programmes

Programme	Decision point	Programme fails	Delay of one year	Delay of two years
Nuclear programme	Early 2011	Replace 10 GW of nuclear capacity with: 38 GW of wind; 19 GW of solar; 10 GW of import base-load (hydro, coal or gas); 10 GW of "cleaner coal" (with consequences for emissions); Combinations of above, with some CCGT	Replace 1,6 GW of capacity in 2023 with: 6,4 GW of wind; 3,2 GW of solar; 1,6 GW of import base-load; 1,6 GW of "cleaner coal"; Combinations of above, with some CCGT	Replace 3,2 GW of capacity in 2022/3 with: 13 GW of wind; 6,4 GW of solar; 3,2 GW of import base-load; 3,2 GW of "cleaner coal"; Combinations of above, with some CCGT
LNG infrastructure	Early 2011	Replace 2 GW of CCGT capacity with: 2 GW of import base-load options; 2 GW of "cleaner coal" options. (3)	Replace 500 MW of capacity in 2019 with: 500 MW of import base-load; 500 MW of "cleaner coal"	Replace 1,2 GW of capacity in 2019/20 with: 1,2 GW of import base-load; 1,2 GW of "cleaner coal"
Execution of EEDSM	Late 2010	Replace 3,5 GW of DSM capacity with: Own generation or co-generation options in the medium term; CCGT, wind or solar options in the longer term (preferably low carbon options)	Replace 750 MW of capacity in 2011 with: Nothing – there being no viable options in the near term until own generation options become viable.	Replace 1,5 GW of capacity in 2011/2 with: Nothing – there being no viable options in the near term until own generation options become viable
Wind programme beyond REFIT (1)	Late 2011	From a security of supply point of view there is a limited impact, but from a carbon reduction point of view the capacity must be replaced by low carbon sources (solar, imports, additional EEDSM)	-	-

Solar programme beyond REFIT (1,2)	Early 2011	From a security of supply point of view there is a limited impact, but from a carbon reduction point of view the capacity must be replaced by low carbon sources (wind, imports, additional EEDSM)	-	-
Import hydro options	Early 2012	Replace 3,5 GW of hydro capacity with: 3,5 GW of alternative import options (including coal); 14 GW of wind; 7 GW of solar; 7 GW of mid-merit CCGT; 7 GW of "cleaner coal" Combinations of the above	Replace 360 MW of hydro capacity with: 360 MW of alternative import options (including coal); 1,4 GW of wind; 720 MW of solar; 360 MW of mid-merit CCGT; 360 MW of "cleaner coal" Combinations of the above	Replace 1,1 GW of hydro capacity with: 1,1 GW of alternative import options (including coal); 4,4 GW of wind; 2,2 GW of solar; 1,1 GW of mid-merit CCGT; 1,1 GW of "cleaner coal" Combinations of the above

Note: (1) Wind and solar capacity can be procured via staggered tranches. Unlike CCGT there is less supporting infrastructure required to make this happen.
(2) The solar capacity can be supported through the solar park concept which provides a co-ordinated approach to supporting transmission and water infrastructure and other development requirements.
(3) CCGT provides operating reserve support for variable output technologies and thus these do not provide appropriate alternatives to CCGT capacity. Small-scale coal could be possible by 2019 (especially via FBC or similar technology).

6.3. IRP projects

Figure 12 provides a summary of the proposed capacities per technology in the draft IRP and the necessary decision points for each of the "programmes" or generic options identified in the draft IRP. The programmes highlighted in RED are those for which the decision point has already passed. If decisions have not been taken by the relevant stakeholders these options may not materialise as expected. The expected lags, or implementation times, required for the programmes are based on assumptions regarding the time taken for environmental assessments, business case approval, procurement processes (for independent power producers or equipment) and the construction of the plant and supporting infrastructure (transmission, water, or other as required).

Programmes highlighted in ORANGE have imminent decision points and should receive higher priority. Those highlighted in YELLOW still have some leeway before the decisions are required. If the feasibility study and allocation decision highlighted above is delayed, this could jeopardise the success of these programmes. The decision period indicated does not at this stage include the full feasibility and allocation programme, thus programmes in ORANGE are already at risk unless the feasibility process is by-passed by a Ministerial determination outside the current regulations.

The RED programmes require immediate determination and execution. These include:

a) Own generation and co-generation: There are already processes under way where certain electricity consumers are developing their own projects. A potential bottleneck for this process could be a national third party access (or wheeling) framework, which supports generators being able to supply Eskom or municipal customers via the existing transmission and distribution networks. This is something Eskom is focusing on.
b) Department of Energy Open Cycle Gas Turbine (OCGT) IPP: If the IPP is required by 2013 as proposed, the procurement process must now be finalised and financial closure reached by early 2011.
c) Renewable Energy Feed-in Tariff (REFIT) options: The procurement process must now be finalised and executed in order to achieve the requirements in the IRP 2010. We are already late in meeting the expectations for wind, small hydro and landfill from this programme as proposed in the IRP and this must be expedited.
d) Wind (after REFIT): If the decision is taken to go the full procurement path (i.e. IPPs) then a procurement process must be followed, leading to financial closure in time to allow three years for environmental impact assessments (EIAs) and construction. There is no time for a full procurement process at the proposed build rate in the IRP. Since wind projects are not essential to the security of supply during this period, slippage is possible without jeopardising the system, but priority must be given to fulfil this programme.

Decisions are imminent for the ORANGE programmes:

a) The nuclear fleet: A decision on the execution of the programme will be required in early 2011 in order to ensure the supporting infrastructure and mechanisms are put in place in time, as well as to ensure that financing and commercial mechanisms are explored to support the fleet deployment. The existing regulations do not require an allocation decision for nuclear, therefore the Minister can make an immediate determination to expedite the process; and
b) The solar fleet: A decision will also be required during 2011 to support the development of a fleet as expected in the IRP.

While it may appear that some decisions can be delayed, i.e. YELLOW programmes, this is not necessarily the case given the need for a feasibility study and allocation. In particular:

a) The Combined Cycle Gas Turbine (CCGT) deployment requires supporting liquefied natural gas (LNG) importing infrastructure, which would be on critical path if delayed beyond early 2011. This decision would be required, regardless of who is allocated the responsibility for the build. This process could be mitigated by asking PetroSA or another entity to start investigating the development of this infrastructure.
b) The import hydro options do not require an allocation decision since these involve IPPs and require an immediate assignment by the Minister of the Single Buyer Officer as the designated Buyer to kick off the programmes. The transmission infrastructure is critical to the success of these programmes and should be initiated immediately, specifically the decisions around infrastructure required in neighbouring countries and the risk allocation for the financing of this infrastructure.

Figure 12. Decision points for IRP projects or programmes

			2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Non Committed Build	New coal options	Balanced Revised	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	750	2000	750	1500
		Key Decision								RFQ		1yr B-Case + 3yr EIA + App + 5yr cons = 8 Year											
	Cogeneration, own build	Balanced Revised	0	103	0	124	426	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Key Decision	1yr B/C, Proc +2yr cons = 3 yr																				
	Gas CCGT	Balanced Revised	0	0	0	0	0	0	0	0	0	474	711	711	0	0	0	0	0	0	0	0	0
		Key Decision		RFQ 1y		1yr B-Case + 1yr App + 1yr Proc +3yr cons = 6 Year																	
	Gas OCGT	Balanced Revised	0	0	0	0	0	0	0	0	0	0	0	0	805	805	575	805	0	805	805	805	345
		Key Decision					RFQ 1y	1yr B-Case + 1yr App + 1yr Proc +3yr cons = 6 Year															
	Import Hydro	Balanced Revised	0	0	0	0	0	0	0	0	0	0	360	750	1110	1129	0	0	0	0	0	0	0
		Key Decision			1yr B-Case & MOU + 3yr EIA + App + 4yr cons = 8 Year																		
	Wind	Balanced Revised	0	0	0	0	200	400	800	800	800	800	0	0	0	0	0	0	0	0	0	0	0
		Key Decision	RFQ 1y	1yr B/c,Proc +2yr cons = 3 Yr																			
	Solar PV, CSP	Balanced Revised	0	0	0	0	0	0	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0
		Key Decision		1yr B-Case + 1yr App + 1yr Proc +2yr cons = 5 Year																			
	Renewables (Wind, Solar CSP, Solar PV, Landfill, Biomass, etc.)	Balanced Revised	0	0	0	0	0	0	0	0	0	0	800	800	800	800	800	1400	600	1200	0	0	0
		Key Decision						1yr B-Case + 1yr App + 1yr Proc +2yr cons = 5 Year															
	Nuclear Fleet	Balanced Revised														1600	1600	1600	1600	0	1600	1600	
		Key Decision		1yr Gov MOU & B-Case & NNR + 1yr Negotiation & Review + 1yr Risk + 8yr cons + 1yr Slippage = 12 Year																			
Committed Build	DOE OCGT IPP	Balanced Revised	0	0	0	1020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Key Decision																					
	REFIT Wind	Balanced Revised	0	200	200	300	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Key Decision	1yr App, Proc +3yr cons = 4 Year																				
	REFIT CSP	Balanced Revised	0	0	0	0	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Key Decision		1yr B/c,Proc +2yr cons = 3 Yr																			
	REFIT Landfill, hydro	Balanced Revised	0	0	100	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Key Decision	1yr B/c,Proc +2yr cons = 3 Yr																				

RFQ = Request for Qualification (for commercial tender to supply energy)
B-Case or B/C = Business Case development
Proc = Procurement process
EIA = Environmental Impact Assessment
App = Project approval
Cons = Construction
MOU = Inter-governmental memorandum of understanding

7. CONCLUSION

The Revised Balanced Scenario provides a solid basis on which to construct the proposed IRP as it combines the main elements that meet the criteria determined by government stakeholders. This plan includes:

- The continuation of Eskom's committed build programme (including the return to service of Grootvlei and Komati power stations, and the construction of Medupi (4332 MW), Kusile (4338 MW) and Ingula (1332 MW) power stations);
- The construction of the Sere power station (100 MW wind farm);
- Phase 1 of the Renewable Energy power purchase programme linked to the National Energy Regulator of South Africa (NERSA) Renewable Energy Feed-in Tariff (REFIT1) programme amounting to 1025 MW (made up of wind, concentrated solar power (CSP), landfill and small hydro options);
- Phase 1 of the Medium Term Power Purchase programme of 390 MW (made up of co-generation and own build options);
- The Department of Energy's Open Cycle Gas Turbine (OCGT) IPP programme of 1020 MW;
- A nuclear fleet strategy, commencing in 2023, of at least 9,6 GW by 2030. The nuclear costs included in the IRP are generic values as for the other technologies and are not intended to tie the IRP to a specific technology;
- A wind programme in addition to the REFIT1 wind capacity, commencing in 2014, of a minimum 3,8 GW;
- A solar programme in addition to the REFIT1 solar capacity, commencing in 2016, of a minimum 400 MW. This does not include solar water heating, which is included in the DSM programme (to the extent of 1617 MW);
- A renewable programme from 2020, incorporating all renewable options, inclusive of wind, solar CSP, solar photo-voltaic, landfill, and hydro, amongst others) of an additional 7,2 GW;
- Imported hydro options from the region totalling 3349 MW from 2020 to 2023;
- CCGT capacity, fuelled with imported LNG, totalling 1896 MW from 2019 to 2021;
- Own generation or co-generation options of 1253 MW as identified in the Medium Term Risk Assessment study;
- Up to 5 GW of generic coal based power generation from 2027 to 2030 (in addition to Medupi and Kusile). The choice of technology could be traditional pulverised fuel or clean coal technologies. The builder of the capacity could be Eskom, South African IPPs or regional IPPs. The choice of technology will be based on current assessments of carbon capture and storage sites and the impact on climate change mitigation targets. With the commercialisation of carbon sequestration technologies, additional coal options could become viable. However for this IRP it was assumed that such technologies are not sufficiently developed to be included. Further iterations of the IRP could revisit this;
- Up to 5750 MW of peaking OCGT. This option could also be provided by demand response programmes; and
- Eskom's current demand-side management (DSM) programme as stipulated in the multi-year price determination (MYPD) application has been incorporated. The breakdown of associated technologies for DSM is included in Appendix B indicating the expected savings from the various constituent programmes.

A number of critical assumptions were included in the development of the proposed IRP 2010. These include:

- The development of a nuclear strategy to provide low emission base-load alternatives to coal-fired generation from 2023;
- The development of a renewable strategy to support a low carbon energy future, specifically developing local industries that support a significant rollout of wind, solar and other renewable technologies;
- The development of infrastructure to support the importation of liquefied natural gas;
- Continued investment in the maintenance and refurbishment of existing Eskom (and non-Eskom) plant to ensure generator performance at assumed levels; and

- Continued investment in DSM initiatives to improve energy efficiency and delay additional capacity requirements. This includes the expected load reduction stemming from the Department of Energy's one million solar water geyser target.

APPENDIX A – ENERGY AND DEMAND FORECAST

A.1. ASSUMPTIONS

Although the IRP 2010 has a time horizon of 20 years, the load forecast covers the period 2010 to 2035.

The IRP 2010 Revision 2 load forecast covers the total requirement for electricity generation to meet the needs of South Africa, including the needs of neighbouring states and international customers (assuming existing contracts continue at current export volumes). The forecast includes the total energy requirements of all consumers, irrespective of the source of this generation (which may be a result of self-generation or co-generation).

Demand-side management initiatives that are planned (i.e., not yet realised) are excluded from the forecast, since these are included in the planning process to be treated similarly to supply-side options.

Economic growth
A strong correlation exists between the GDP growth and the electricity sales growth, and the electricity sales forecast is based to a large extent on this relationship. The two assumptions underlying this relationship are the forecast GDP and the electricity intensity.

The AsgiSA targeted growth of 6% GDP growth by 2014 is currently used as a base for the **high GDP growth forecast**. The intention of this target was also to halve unemployment by about 2014. The model assumes an adjustment to the target date (delaying to 2016) to compensate for the impact of the global economic recession. Although this might be seen as an optimistic target, GDP growth rates of close to 6% were achieved in the recent past. While the growth is expected at 6% per annum for a large portion of the forecast period, this is expected to gradually decline over time to 5,3% in 2035. Thus the average annual growth rate of the high GDP growth forecast over the period of 2010 to 2035 is 5.5% per annum.

The **moderate GDP growth forecast** is similar to the average historical GDP growth over the last few years. The latter is also seen as the potential growth if the AsgiSA targets are not achieved, and are also close to the potential growth of the South African economy as seen by the South African Reserve Bank. This is also in line with the forecasts made by many institutions over the medium term. The average annual GDP growth of this forecast is approximately 4.5% between 2010 and 2035.

The low GDP growth forecast is about 1% lower, on an average annual basis, than the moderate GDP forecast. This is also in line with **low growth** scenarios which were part of the scenario exercise referred to above. During the past twenty years a narrow cone of ± 1% growth was found very realistic and appropriate for long term planning and therefore the values assumed for the GDP growth rates are as per the table below.

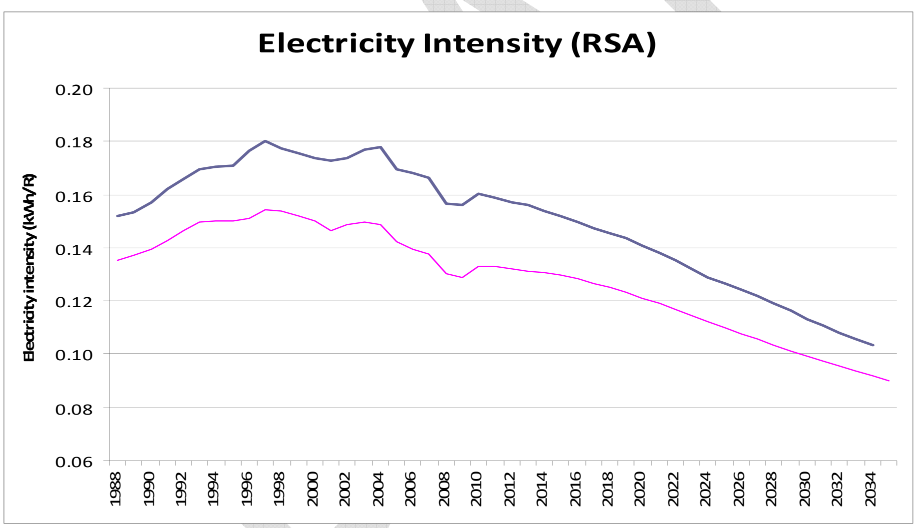
Table 6. Assumptions for GDP growth rates 2010-2035

GDP - growth rate assumptions							
Year	Moderate	High	Low	Year	Moderate	High	Low
2008	3.68	3.68	3.68	2022	4.90	5.90	3.90
2009	-1.70	-1.70	-1.70	2023	4.80	5.80	3.80
2010	2.50	3.50	1.50	2024	4.80	5.80	3.80
2011	3.70	4.70	2.70	2025	4.80	5.80	3.80
2012	4.00	5.00	3.00	2026	4.70	5.70	3.70
2013	4.00	5.00	3.00	2027	4.70	5.70	3.70
2014	4.00	5.00	3.00	2028	4.70	5.70	3.70
2015	4.50	5.50	3.50	2029	4.60	5.60	3.60
2016	5.00	6.00	4.00	2030	4.60	5.60	3.60
2017	5.00	6.00	4.00	2031	4.50	5.50	3.50
2018	5.00	6.00	4.00	2032	4.50	5.50	3.50
2019	5.00	6.00	4.00	2033	4.40	5.40	3.40
2020	5.00	6.00	4.00	2034	4.40	5.40	3.40
2021	4.90	5.90	3.90	2035	4.30	5.30	3.30

Electricity intensity

This parameter is not a specific input to the demand forecast model, but is used as a check to determine the correct trajectory for electricity demand (relative to economic growth).

Figure 13. Electricity intensity for South Africa



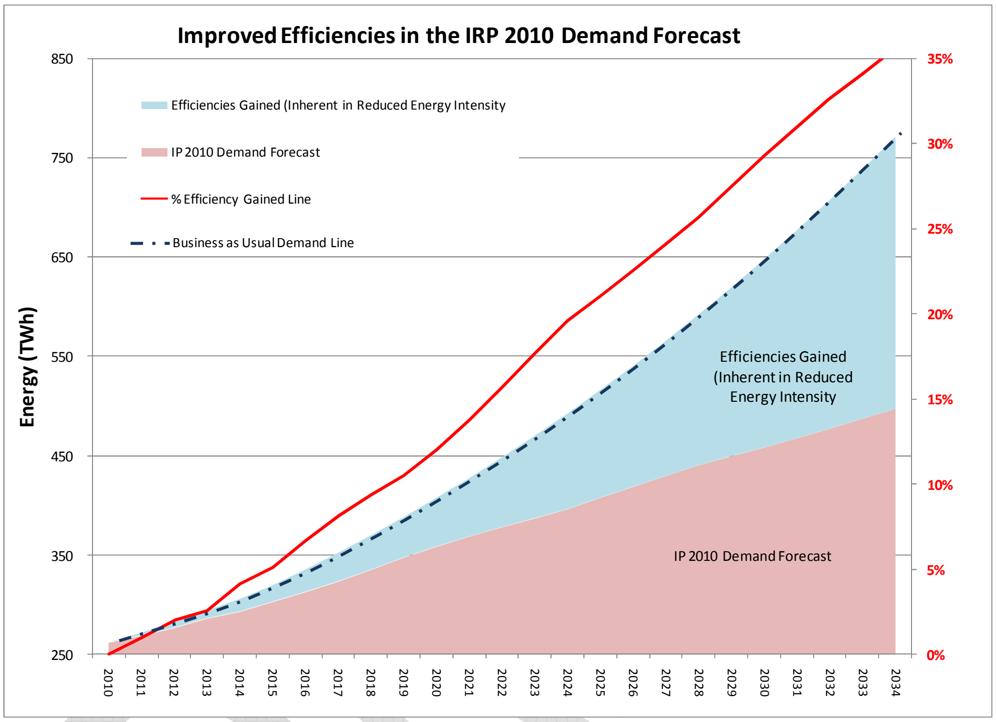
The electricity intensity of the economy is a measure of the ratio of electricity energy consumption relative to the Gross Domestic Product (GDP). This can be expressed at basic prices and market prices.

The recent historic trend is indicate in the graph above (comparing total South African consumption, including losses, to gross value added at basic prices in blue (constant 2005 prices)), with the intensity at 2009 sitting at 0,16kWh/R of gross value added. The intensity based on the gross value added at market prices (constant 2005 prices) is indicated by the purple line with the intensity at 2009 sitting at 0,129kWh/R of gross value added. The energy intensity will gradually decline from the 0,16kWh/R in 2009 to 0,1kWh/R in 2034 at basic prices.

It is expected that, following the trend of developed countries, the tertiary sector of the economy (which is less energy intensive) should grow at a faster rate than the primary or secondary sectors. High price increases for electricity should also induce a certain amount of substitution to alternative energy sources, or increased energy efficiency, which should reduce the electricity intensity in the economy.

The decline in energy intensity also provides an indication of the expected improvement in energy efficiency. If the economy grows as per the expected economic growth without any change in energy intensity the expected demand should be significantly higher (at 770 TWh by 2034). Due to the expected shift from energy intensive industries to less intensive economic activity, coupled with efficiency improvements caused by higher prices, the efficiency savings brings the expected demand down to 496TWh, a saving of 35%.

Figure 14. Improved efficiencies in the IRP 2010 demand forecast



Price elasticity of demand
The forecasting models do not include this parameter at present. Price increases in electricity will have two separate impacts on electricity demand: through income effects which will impact on GDP growth (price increases may reduce income and expenditure through the impact on disposable income) and through substitution effects which will have a direct impact on electricity demand. The former is captured in the assumptions on GDP growth, the latter in the future electricity intensity.

Forecasting peak demand
The long-term forecast for electrical energy is the key input from which the long-term *demand* forecast (i.e. the forecast for the annual demand profile) is derived. The long-term energy forecast and the long-term demand forecast determine the energy and capacity requirements respectively, which must be met through the IRP for 2010. The demand forecast was calculated based on the energy forecast.

A.2. MODELS

The System Operator used an in-house developed methodology for the energy forecast, called the Sectoral Model. The Sectoral Model uses Eskom sales categories as the basis for developing the forecast, and is closely aligned to the Eskom MYPD sales forecast for the first 5 years. The model is a combination of statistical analysis, tracking of historical trends and applying expert knowledge. It is further expanded to include individual forecasts for all of the Eskom key customers. The other Eskom categories are developed per customer service area and the model enables a geographical view per Eskom category.

The CSIR was requested to provide an independent energy forecast. The CSIR used a statistical model which they developed. The model is essentially a multiple regression model forecasting technique, used to forecast the annual consumption within the individual electricity sectors by relating various conditions (or "drivers") to the demand in each sector.

A.3. RESULTS

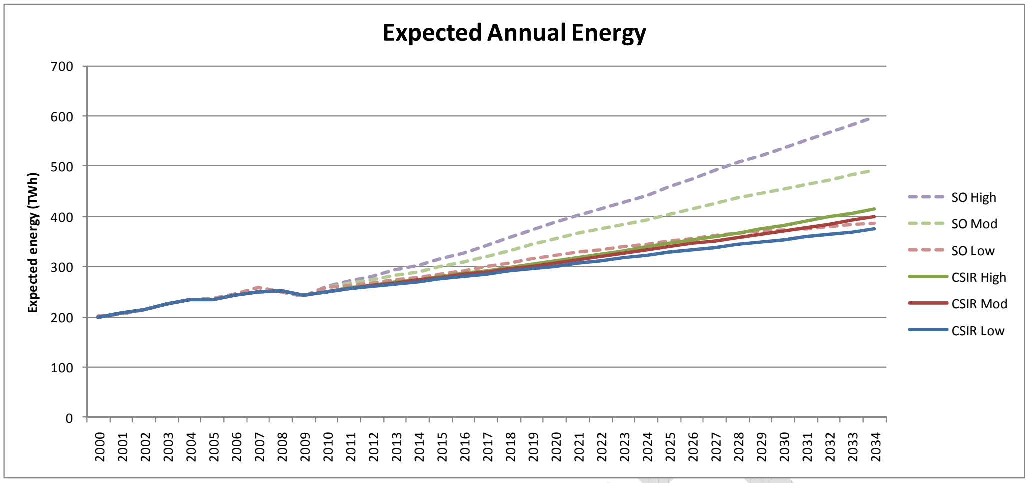
The figure below shows the proposed forecasts for the period up to 2035 using three different GDP assumptions: High – 5,51%, Moderate – 4,51% and Low – 3.51%. These result in electricity growths from the System Operator model of 3,65%, 2,84% and 1,85% respectively. The CSIR model for the same economic growth suggests 2,18%, 2,02% and 1,76% respectively.

Table 7. Expected annual energy requirement 2010-2034

	CSIR Low	CSIR Mod	CSIR High	SO Low	SO Mod	SO High
2010	249,051	249,422	249,626	257,601	259,685	261,769
2011	255,882	256,744	257,693	262,394	266,681	270,969
2012	261,031	262,376	263,682	267,784	274,403	281,022
2013	265,790	267,694	269,169	274,788	283,914	293,041
2014	270,630	272,964	274,497	278,880	290,540	302,201
2015	275,735	278,589	280,341	285,920	300,425	314,930
2016	281,051	284,450	286,545	292,728	310,243	327,758
2017	285,930	289,983	292,552	299,991	320,751	341,511
2018	290,870	295,628	298,548	308,036	332,381	356,725
2019	296,027	301,486	304,790	316,501	344,726	372,950
2020	301,255	307,503	311,226	323,498	355,694	387,891
2021	306,544	313,601	317,996	329,556	365,826	402,095
2022	311,934	319,869	324,928	334,587	375,033	415,480
2023	317,465	326,326	331,948	339,160	383,914	428,668
2024	323,104	332,998	339,306	343,634	392,880	442,126
2025	328,456	339,436	346,399	350,065	404,358	458,650
2026	333,733	345,864	353,525	355,785	415,281	474,777
2027	338,636	352,012	360,379	361,300	426,196	491,093
2028	343,651	358,365	367,618	366,319	436,761	507,204
2029	348,758	364,884	375,017	370,007	445,888	521,769
2030	353,979	371,616	382,774	372,947	454,357	535,766
2031	359,240	378,322	390,643	376,272	463,503	550,734
2032	364,479	385,185	398,831	379,737	473,046	566,356
2033	369,735	392,205	407,027	383,410	483,075	582,740
2034	375,107	399,384	415,456	386,404	492,540	598,677

Note: CSIR Low, Moderate and High reflect the three economic trajectories, as with the System Operator (SO) Low, Moderate and High.

Figure 15. Expected annual energy requirement 2010-2034



Peak demand

The initial observations were that the load factor was increasing over the forecasted period. This is because the high load factor sectors are dominant in the customer mix of the energy forecast. The energy forecast of the smelters sector is almost constant whereas the industrial sector as a whole is increasing. This led to the load factor being over-stated as the load factor for smelters is very high and it forms a significant portion of the Industrial sector. To rectify this, the smelters sector was separated from the industrial sector. Two new profiles, i.e. “new” industrial and smelters sector, were then formed and used in the new forecast. The load factor then gradually decreased towards the end of the forecast period.

The actual profiles for 2007 to 2009 did not provide appropriate indicators for future profiles as these years contain abnormalities caused by supply constraints (in particular interruptions and load shedding). To rectify this, “corrected” profiles were used instead.

Using the sector mix from the energy forecast and confirmed by the model calculations, indications are that the system will remain at a high load factor for a considerable number of years. The current dominating sectors for electricity consumption have very high load factors, and are expected to remain dominant for some time to come. In-depth research needs to be undertaken on these sectors to quantify how issues like beneficiation will impact the load factor.

Table 8. Annual maximum demand 2010-2034

Year	High Maximum Demand (MW)	Low Maximum Demand (MW)	Moderate Maximum Demand (MW)	2010 IRP Rev1 Maximum Demand (MW)	CSIR_Moderate (MW)
2010	39216	38587	38885	38838	38388
2011	40629	39319	39956	40230	39084
2012	42027	40002	40995	41355	39828
2013	43839	41040	42416	42832	40639
2014	45255	41669	43436	44776	41471
2015	47124	42666	44865	47139	42283
2016	48479	43157	45786	48944	42603
2017	51090	44710	47870	50786	43923
2018	53276	45815	49516	52334	44698
2019	55573	46952	51233	54040	45477
2020	57649	47848	52719	55920	46374
2021	59885	48828	54326	57562	47271
2022	61932	49596	55734	59293	48251
2023	63955	50299	57097	61121	49264
2024	65870	50872	58340	62928	50221
2025	68458	51903	60150	64866	51171
2026	70866	52737	61770	66717	52049
2027	73320	53550	63404	68591	52981
2028	75606	54191	64867	70207	53975
2029	78066	54917	66460	72176	55017
2030	80272	55408	67809	73988	56101
2031	82625	55955	69258	75867	57180
2032	84895	56399	70615	77464	58303
2033	87641	57112	72344	79570	59405
2034	90162	57616	73856	81626	60567

APPENDIX B – DEMAND SIDE INTERVENTIONS

B.1. MANDATORY PROGRAMMES

The Eskom DSM programme, as submitted by Eskom in the 2010 MYPD, is included in the IRP 2010 as a committed programme. While historic results (from previous demand-side management programmes) are locked into the demand forecast, future DSM initiatives are not included in the demand forecast, but are included in the IRP 2010 model as committed programmes.

Table 9. Eskom DSM programme

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Comp Air	Capacity (MW)	39	76	115	151	211	275	275	275	275	275	275
	Energy (GWh)	297	581	881	1158	1619	2110	2110	2110	2110	2110	2110
Heat Pumps	Capacity (MW)	3	35	110	282	463	522	581	640	640	640	640
	Energy (GWh)	14	142	445	1,137	1,866	2,104	2,341	2,579	2,579	2,579	2,579
Lighting HVAC	Capacity (MW)	106	137	169	199	233	271	271	271	271	271	271
	Energy (GWh)	673	874	1,074	1,266	1,482	1,724	1,724	1,724	1,724	1,724	1,724
New Initiatives	Capacity (MW)	-	-	-	17	38	68	68	68	68	68	68
	Energy (GWh)	-	-	-	123	275	492	492	492	492	492	492
Process Optimisation	Capacity (MW)	81	151	210	293	384	467	467	467	467	467	467
	Energy (GWh)	608	1,137	1,582	2,208	2,895	3,521	3,521	3,521	3,521	3,521	3,521
Shower Heads	Capacity (MW)	-	20	85	85	85	85	85	85	85	85	85
	Energy (GWh)	-	58	248	248	248	248	248	248	248	248	248
Solar Water Heating	Capacity (MW)	26	78	123	287	556	910	1,263	1,617	1,617	1,617	1,617
	Energy (GWh)	76	227	360	838	1,622	2,656	3,689	4,722	4,722	4,722	4,722
Total	**Capacity (MW)**	**254**	**496**	**811**	**1,313**	**1,969**	**2,597**	**3,009**	**3,422**	**3,422**	**3,422**	**3,422**
	Energy (GWh)	**1,669**	**3,020**	**4,590**	**6,978**	**10,007**	**12,855**	**14,126**	**15,397**	**15,397**	**15,397**	**15,397**

Note: The capacity indicated here is the adjusted capacity to meet the system peak (as opposed to the peak capacity saving from each individual programme)

Research conducted by Eskom indicates that this programme may only scratch the surface of the potential market for EEDSM (which has been estimated at 12933 MW of total market potential). The approved Eskom programme, which is included in the IRP, has been developed based on the most likely options in the medium term.

Energy efficiency (as a separate concept to DSM) covers the use of electricity by consumers. The effect of the price increases would impact on energy efficiency and has been catered for in the electricity intensity parameter sheet. DSM will include specific programmes (or interventions) which may target energy efficiency. These are included above.

While the public participation process provided good direction and ideas on future programmes, there remains little additional information to test these programmes. Thus for this iteration of the IRP the Eskom DSM programme has had to be relied on.

The energy conservation scheme (ECS) is not included in the IRP 2010 as this is seen as a medium term measure to deal with the current shortfall in capacity until 2015 when new generation capacity can provide the required demand.

B.2. OPTIONS

In the long run it is expected that additional EEDSM options, with correct costs and anticipated energy savings, should compete with supply-side options, to the extent that new capacity is delayed by the introduction of new EEDSM programmes. The enhanced DSM scenario tests the impact of additional DSM programmes but without programme costs it is only possible to indicate the potential savings from such programmes.

APPENDIX C – SUPPLY-SIDE OPTIONS

C.1. TECHNOLOGY CHOICES

The IRP 2010 starts off with the existing fleet of power stations available in South Africa, together with existing import contracts, to define the existing supply of electricity which is available for distribution from second to second to electricity users. Committed projects to expand existing facilities or to build new facilities are added to the fleet at the expected dates of completion of the projects to ensure the IRP 2010 will reflect a realistic situation in the medium term. For future years the software modelling tool is allowed to choose the appropriate supply options to satisfy demand in the most cost effective way, while satisfying different constraints as defined in various scenarios. These future supply options are contained in a data base where the capital cost of facilities as well as the fuel and operational cost of each option is specified. This chapter intends to describe the supply options used in the IRP 2010 development process.

Existing Fleet of Power Stations
Eskom has 22 operational power stations with a combined capacity of 40 635 MW. The oldest power station (Komati) started production in 1961 and was fully operational by 1966. After being fully mothballed in 1990 Komati was brought back into service and should be fully operational again in 2011. Camden and Grootvlei were also mothballed in the early 1990s and were brought back to service in the last few years.

Table 10. Existing South African generation capacity assumed for IRP

	Capacity (MW)
Eskom	**40635**
Camden	1520
Grootvlei	372
Komati	202
Arnot	2280
Hendrina	1870
Kriel	2850
Duvha	3450
Matla	3450
Kendal	3840
Lethabo	3558
Matimba	3690
Tutuka	3510
Majuba	3843
Koeberg	1800
Gariep	360
VanderKloof	240
Drakensberg	1000
Palmiet	400
Acacia and Port Rex	342
Ankerlig and Gourikwa	2058
Non-Eskom	**3260**
TOTAL	**43895**

Two pump storage power stations (Drakensberg and Palmiet) are being used as peaking supplies together with four gas turbine power stations, of which two are small and more than 30 years old (Acacia and Port Rex) and the other two are bigger and less than 5 years old (Ankerlig and Gourikwa). Two hydro power stations in the Orange River (Gariep and Vanderkloof) are in operation, and one nuclear power station (Koeberg) is used for base-load generation. The remaining ten power stations are coal fired base-load power stations.

Non-Eskom generation is dominated by the Cahora Bassa import of 1 500 MW. Other non-Eskom sources in South Africa consist of municipal generators and private generation under the medium term power purchase programme.

Table 11. Existing non-Eskom generation

	Capacity (MW)	Load factor (%)
Coal-fired		
Kelvin A	50	62,4
Kelvin B	155	62,4
Rooiwal	155	62,4
Pretoria West	75	62,4
Sasol SSF - Coal-fired PF	520	62,4
Sasol Infrachem - Coal-fired PF	130	62,4
Pumped Storage		
Steenbras	180	20
Limited Energy Plant		
Mini Hydro (First Falls, Second Falls, Mbashe and Ncore)	70	62,4
Sappi Stanger	155	62,4
Mondi Merebank	50	62,4
Mondi Felixton	10	62,4
Mondi Umhlathuze	13	62,4
Methane Waste Gas	9	62,4
Sugar Mills	100	62,4
Mossgas	90	62,4

Notes:

(1) Kelvin power station has had operational issues in the recent past – the power station capacity is limited to that used in IRP 2010 Rev 1 (205 MW, as above).

(2) No non-Eskom emergency gas turbine capacity is included in the IRP 2010 model.

Some of the older power stations will reach the end of their respective economic life during the planning period incorporated in this IRP. Some of the non-Eskom generators will be de-commissioned from 2015 onwards, with substantial Eskom de-commissioning starting in 2022. Table 12 provides the expected decommissioned capacity.

In total, the existing installed capacity available to South Africa is 43895 MW. This capacity will be increased with a number of committed projects over the medium term. The following committed projects are included in this IRP development, with commissioning dates, as shown in the table below. The capacity is included if it is available before the peak of the year in question, for example no additional units are expected to be commissioned at Komati before the peak in 2010, however additional capacity commissioned after the peak will reflect in the following year.

Table 12. Committed new capacity and decommissioning

Year	Grootvlei (RTS)	Komati (RTS)	Medupi	Kusile	DoE OCGT IPP	Ingula	MTPPP 1	REFIT Wind	REFIT Other	Sere	Decommissioning	Net new capacity
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2010	380	0	0	0	0	0	260	0	0	0	0	640
2011	376	303	0	0	0	0	130	200	0	0	0	1009
2012	0	303	722	0	0	0	0	200	100	100	0	1425
2013	0	101	722	0	1020	333	0	300	125	0	0	2601
2014	0	0	1444	0	0	999	0	0	100	0	0	2543
2015	0	0	722	1446	0	0	0	0	0	0	-180	1988
2016	0	0	722	723	0	0	0	0	0	0	-90	1355
2017	0	0	0	1446	0	0	0	0	0	0	0	1446
2018	0	0	0	723	0	0	0	0	0	0	0	723
2019	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	-75	-75
2022	0	0	0	0	0	0	0	0	0	0	-1870	-1870
2023	0	0	0	0	0	0	0	0	0	0	-2280	-2280
2024	0	0	0	0	0	0	0	0	0	0	-909	-909
2025	0	0	0	0	0	0	0	0	0	0	-1520	-1520
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	-2850	-2850
2029	0	0	0	0	0	0	0	0	0	0	-1128	-1128
2030	0	0	0	0	0	0	0	0	0	0	0	0

After all these options are implemented, the IRP 2010 development process will start to bring new supply options into the plan. This will be done in a process that optimises the cost and any other factors that might constrain the plan, for example CO_2 emissions, or any government policy position that might specify targets for renewable energy production levels. The cost of available technologies is specified in the data input files, both for capital spending requirements as well as for production costs, be it fixed annual costs or variable production costs. The tables below give a reduced data sample for various supply options, using data from the final EPRI report on South African costs.

Table 13. Generic supply-side option costs

	Pulverised Coal with FGD	**Fluidised bed with FGD**	**Nuclear Areva EPR**	**OCGT**	**CCGT**	**Wind**	**Concentrated PV**	**Forestry residue biomass**	**Municipal solid waste biomass**	**Pumped storage**	**Integrated Gasification Combined Cycle (IGCC)**	**CSP, parabolic trough, 3 hrs storage**	**CSP, parabolic trough, 6 hrs storage**	**CSP, parabolic trough, 9 hrs storage**
Capacity, rated net	6X750 MW	6X250 MW	6X1600 MW	114,7 MW	711,3 MW	100X2 MW	10 MW	25 MW	25 MW	4X375 MW	1288 MW	125 MW	125 MW	125 MW
Life of programme	30	30	60	30	30	20	25	30	30	50	30	30	30	30
Lead time	9	9	16	2	3	3-6	2	3,5-4	3,5-4	8	5	4	4	4
Typical load factor (%)	85%	85%	92%	10%	50%	29% (7,8m/s wind @ 80m)	26,8%	85%	85%	20%	85%	31,2%	36,3%	43,7%
Variable O&M (R/MWh)	44,4	99,1	95,2	0	0	0	0	31,1	38,2	4	14,4	0	0	0
Fixed O&M (R/kW/a)	455	365	-	70	148	266	502	972	2579	123	830	513	562	635
Variable Fuel costs (R/GJ)	15	7,5	6,25	200	74,4	-	-	19,5	0	-	15	-	-	-
Fuel Energy Content, HHV, kJ/kg	19220	12500	3,900,000,000	39,3 MJ/SCM	39,3 MJ/SCM	-	-	11760	11390	-	19220	-	-	-
Heat Rate, kJ/kWh, avg	9769	10081	10760	11926	7468	-	-	14185	18580	-	9758	-	-	-
Overnight capital costs (R/kW)	17785	14965	26575	3955	5780	14445	37225	33270	66900	7913	24670	37425	43385	50910
Phasing in capital spent (% per year) (* indicates commissioning year of 1st unit)	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%	3%, 3%, 7%, 7%, 8%, 8%, 8%, 8%, 8%, 8%, 8%, 8%*, 6%, 6%, 2%, 2%	90%, 10%	40%, 50%, 10%	2,5%, 2,5%, 5%, 15%, 75%	10%, 90%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	3%, 16%, 17%, 21%, 20%, 14%, 7%, 2%*	5%, 18%, 35%, 32%*, 10%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%
Equivalent Avail	91,7	90,4	92-95	88,8	88,8	94-97	95	90	90	94	85,7	95	95	95
Maintenance	4,8	5,7	N/A	6,9	6,9	6	5	4	4	5	4,7	-	-	-
Unplanned outages	3,7	4,1	<2%	4,6	4,6	-	-	6	6	1	10,1	-	-	-
Water usage, l/MWh	229,1	33,3	6000 (sea)	19,8	12,8	-	-	210	200	-	256,8	250	245	245
Sorbent usage, kg/MWh	15,2	28,4	-	-	-	-	-	-	-	-	-	-	-	-
CO_2 emissions (kg/MWh)	936,2	976,9	-	622	376	-	-	1287	1607	-	857,1	-	-	-
SOx emissions (kg/MWh)	0,45	0,19	-	0	0	-	-	0,78	0,56	-	0,21	-	-	-
NOx emissions (kg/MWh)	2,30	0,20	-	0,28	0,29	-	-	0,61	0,80	-	0,01	-	-	-
Hg (kg/MWh)	1,27E-06	0	-	0	0	-	-	-	-	-	-	-	-	-
Particulates (kg/MWh)	0,13	0,09	-	0	0	-	-	0,16	0,28	-	-	-	-	-
Fly ash (kg/MWh)	168,5	35,1	-	-	-	-	-	24,2	1226	-	9,7	-	-	-
Bottom ash (kg/MWh)	3,32	140,53	-	-	-	-	-	6,1	3000	-	79,8	-	-	-
Expected COD of 1st unit	2018	2016	2022	2013	2016	2013	2018	2014	2014	2018	2018	2018	2018	2018
Annual build limits	-	-	1 unit every 18 months	-	2500 MW after 2017	1600 MW	100 MW					500 MW	500 MW	500 MW

Private generation options are included for 2014 and 2015 using the generic fluidised bed costs.
The nuclear costs included here are generic values as for the other technologies and are not intended to tie the IRP to a specific technology.

Table 14. Assumed project costs for import supply-side options

	Import hydro (Mozambique A)	Import hydro (Mozambique B)	Import coal (Botswana)	Import hydro (Mozambique C)	Import coal (Mozambique)	Import hydro (Zambia A)	Import hydro (Zambia B)	Import hydro (Zambia C)	Import gas (Namibia)
	Hydro	Hydro	Coal	Hydro	Coal	Hydro	Hydro	Hydro	Gas
Capacity	1125 MW	850 MW	1200 MW	160 MW	1000 MW	750 MW	120 MW	360 MW	711 MW
Life of programme	60	60	30	60	30	60	60	60	30
Lead time	9	9	5	4	5	8	3	4	5
Load factors (%)	66,7%	38%	85%	42%	N/A	46%	64%	38%	N/A
Variable O&M (R/MWh)	0	12,1	18	12,1	7,7	12,1	12,1	12,1	0
Fixed O&M (R/kW/a)	344	69,8	379	69,8	160	69,8	69,8	69,8	168
Variable Fuel costs (R/GJ)	N/A	N/A	15	N/A	2,88	N/A	N/A	N/A	74,4
Fixed fuel costs (R/kW/a)	N/A	N/A	-	N/A	-	N/A	N/A	N/A	-
Overnight capital costs (R/kW)	15518	7256	16880	15152	14400	6400	9464	4264	5780
Phasing in capital spent (% per year)	5%, 5%, 5%, 5%, 10%, 25%, 20%, 20%, 5%	5%, 5%, 5%, 5%, 10%, 25%, 20%, 20%, 5%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	5%, 5%, 5%, 5%, 10%, 25%, 25%, 20%	15%, 55%, 30%	10%, 25%, 45%, 20%	40%, 50%, 10%
Equivalent Avail	92	90	91,7	90	91,7	90	90	90	88,8
Maintenance	4	5	4,8	5	4,8	5	5	5	6,9
Unplanned outages	4	5	3,7	5	3,7	5	5	5	4,6
Water usage, l/MWh	-	-	100	-	100	-	-	-	12,8
Sorbent usage, kg/MWh	-	-	0	-	0	-	-	-	-
CO_2 emissions (kg/MWh)	-	-	924,4	-	924,4	-	-	-	376
SOx emissions (kg/MWh)	-	-	8,93	-	8,93	-	-	-	0
NOx emissions (kg/MWh)	-	-	2,26	-	2,26	-	-	-	0
Hg (kg/MWh)	-	-	1,22E-06	-	1,22E-06	-	-	-	0
Particulates (kg/MWh)	-	-	0,12	-	0,12	-	-	-	0
Fly ash (kg/MWh)	-	-	166,4	-	166,4	-	-	-	0
Bottom ash (kg/MWh)	-	-	3,28	-	3,28	-	-	-	0
Expected COD of 1st unit									

Regional projects are not treated as generic. Since many of these are either hydro or gas, there are local considerations that significantly change the costs of the plant (particularly hydro). Thus these options are identified specifically. The cost values used in the modelling are based on commercially sensitive negotiated prices, and thus will not be published. The results of the IRP will not identify specific projects, but assume a generic input from the region.

The costs and other parameters were derived from the SAPP Pool plan, which used 2006 USD. These costs were escalated by (an assumed) 8% to get to 2010 USD, and then R7.40/USD at Jan 2010. Some of these costs have been replaced with the EPRI generic numbers which are more up to date, and with Eskom project numbers where specific values were available.

Table 15. Sugar cane fibre biomass options

Sugar Cane Fibre Cost And Performance Summary (EPRI Executive Summary Format)

Technology	Cane Fibre	Cane Fibre (Felixton)
Rated Capacity MW net	52.5	49
Plant Operating Season per year - weeks	36	36
Plant Cost Estimates (January 2010)		
Capex Rm		
Total Plant Cost Overnight ZAR/kW	21,318	9,429
Lead Times and Project Schedule years	3	2
Expense Schedule % of TPC per year	10%,30%,60%	33%, 67%
Fuel Cost Estimates		
First Year ZAR/GJ	57	57
Expected Escalation	0%	0%
Fuel Energy Content kJ/kg	6,850	6,343
Operation and Maintenance Cost Estimates		
Fixed O&M ZAR/kW-yr	310	115
Variable O&M ZAR/MWh	18	5.9
Availability Estimates (during season)		
Equivalent Availability	95%	95%
Maintenance	3.8%	3.8%
Unplanned Outages	1.2%	1.2%
Availability Estimates (for the year)		
Equivalent Availability	66.0%	66.0%
Maintenance	33.0%	33.0%
Unplanned Outages	1.0%	1.0%
Performance Estimates		
Economic Life years	30	30
Heat Rate kJ/kWh	19,327	26,874
Plant Load Factor		
Typical Capacity Factor during Season	71%	80%
Typical Capacity Factor overall	49%	55%
Maximum of Rated Capacity	100%	100%
Minimum of Rated Capacity	22%	22%
Water Usage		
Per Unit of Energy L/MWh	217	217
Air Emissions kg/MWh		
CO2	2,129	2,807
CO2 Net of renewable CO2	88	115
SOx (as SO2)	0	0
NOx (as NO2)	Negligible	Negligible
Particulates	0.45	0.8
Solid Wastes kg/MWh		
Fly ash	81.7	113.6
Bottom ash	27.3	36.8

The costs for Felixton above are included as an option, but limited to this specific instance/project. The generic cane fibre costs are included as options in the IRP 2010 with a potential of 1000 MW as indicated by Tongaat in its submission.

Learning rates

None of the current scenarios include learning rates for technology options. A test case has yet to be run to determine the impact of learning rates on the optimal choices for the IRP. The following table includes some of the potential learning for specific technologies suggested by the International Energy Agency (IEA), based on the decrease in costs for each technology for every doubling in the global capacity for the technology.

Table 16. Potential learning rates

Technology options	Learning rate for each doubling in capacity (%)
Wind (onshore)	7
Photo-voltaics	18
CSP	10
Biomass	5
IGCC	3
Nuclear III	3

Source: International Energy Agency, Energy Technology Perspectives 2008, Table 5.3. (p 207)

Figure 16. Screening curves for generation technologies (8% net discount rate)

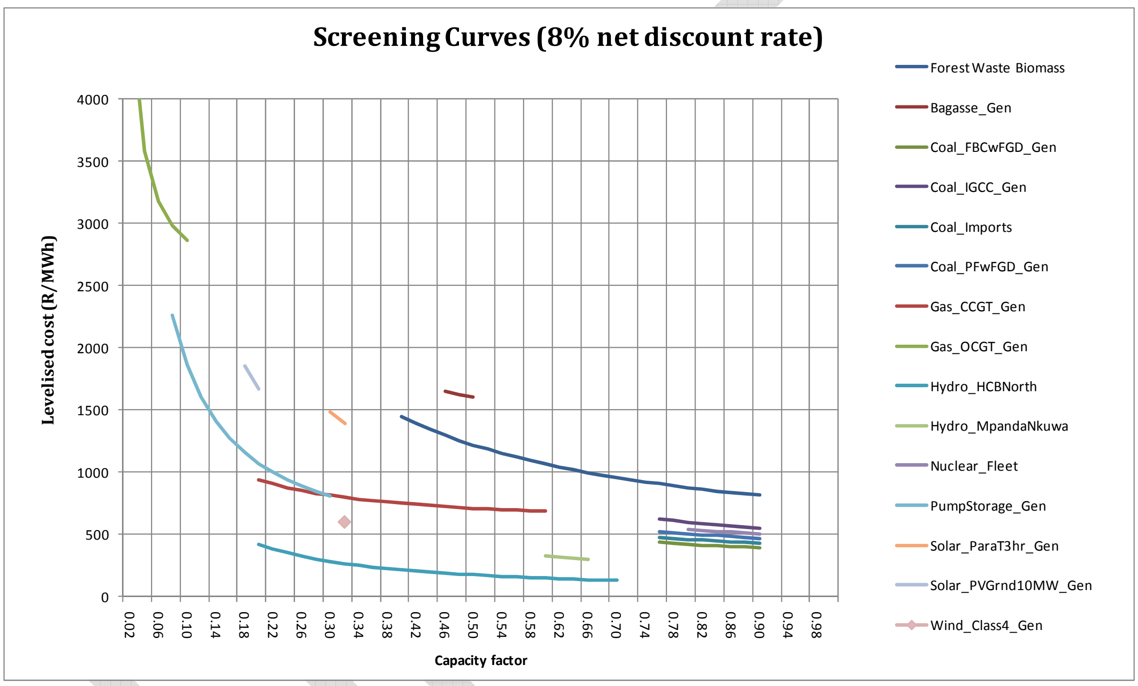
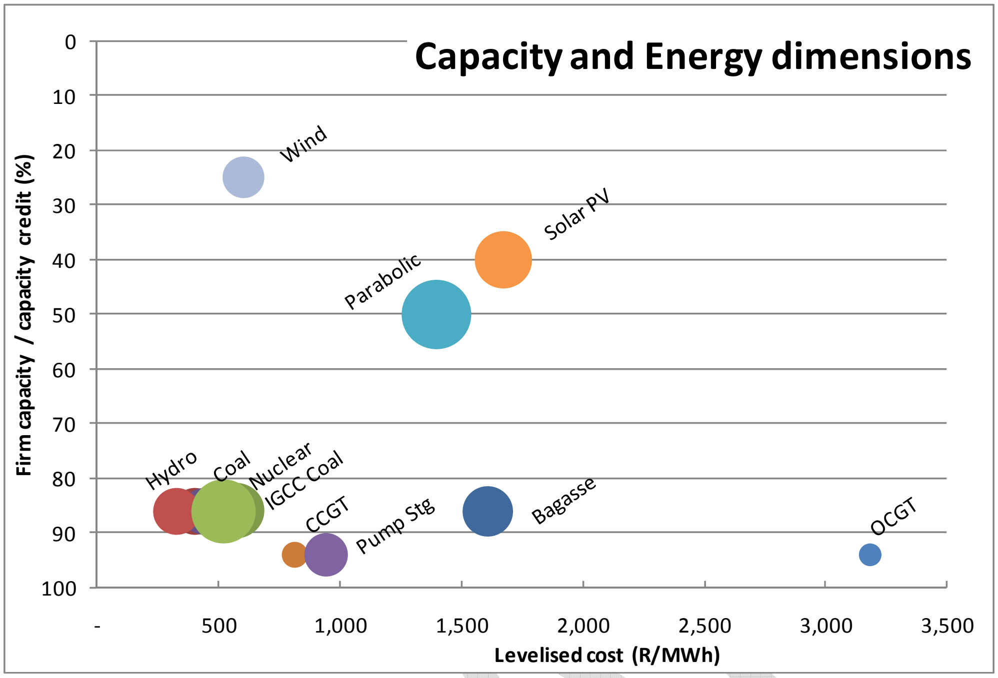


Figure 16 provides an overview of the levelised costs for the generic options for the IRP 2010 based on the potential capacity factor for each technology. In most cases there is a wide range of possible load factors (for example, CCGT or forest waste biomass) whereas others, such as wind and other renewables, are limited to the assumed capacity factor in the IRP 2010 model. This can be significant in terms of the optimisation process in the model where certain technologies can offer capacity for operating reserves. This additional value is not indicated in the screening curve, which is a reflection of the energy dimension of each technology. Figure 17 offers an alternative view relating the levelised cost at an assumed capacity factor against the firm capacity (or capacity credit) offered by each capacity.

This suggests that even though certain technologies may be cheaper on a levelised cost basis the optimal plan would need to consider the capacity available to meet peak demand as well as reserves and the availability of each technology to offer this. Technologies will be limited by the capability to store the fuel, e.g. wind has no ability to store its fuel, concentrated solar has a limited capacity through the molten salts heat storage, pumped storage has the capacity through the water in the dams, and large base-load generators have capability through large fuel storage.

The selection of OCGT as a viable technology for the plan is based on the generation capacity provided at low capital cost to provide reserves and very limited peaking capability with a high degree of certainty but at significant operating costs. This is preferable to pumped storage which has higher capital costs, but lower operating costs.

Figure 17. Capacity and energy dimension



Note: The size of each bubble is based on the relative capital cost (per kW installed capacity) of each technology (in 2010 present value terms)

C.2. TECHNOLOGY-SPECIFIC MODELLING ISSUES

Wind

In the absence of clear data on wind profiles across the country, a number of assumptions were made to generate such profiles for wind generation options. In order to accommodate the likelihood of diversity in wind profiles, four wind categories were developed using the same wind generation characteristics (load factor, costs, etc) but subject to different wind speed profiles.

Each of these profiles was developed based on a four day cycle for wind speed. This assumption is based on findings by GTZ on the experience of wind in Germany. Within this four day cycle the distribution of wind speed is based on a Weibull distribution which caters for the non-normal distribution relating to wind speed. A random generator provided the wind speed in each hour within the constraints of the Weibull distribution and four day cycle. Each of the four profiles was generated randomly but independent of one another. No attempt was made to correlate the profiles with one another, providing some diversity but not generated in order to maximise this diversity.

The wind generation, a function of the wind speed in each hour, is then fixed at this profile over the period of the study. Since this generation is independent of the total system demand profile, the model would choose wind primarily for energy production and less for its contribution to the system capacity, especially where the profile does not closely match the system requirement.

The allocation of wind capacity was constrained to ensure that each of the profiles received an equal share of the capacity through the study period.

Solar

The final EPRI report on generation technology options for the development of the IRP[2] provides profiles for solar generation based on storage options and technology choices. These profiles were used to indicate the generation profile for each solar technology based on a random indication of sunlit days (as opposed to overcast days with no generation). These profiles were developed to ensure that the assumed load factor from each option was met.

[2] EPRI, Power Generation Technology Data for Integrated Resource Plan of South Africa, 2010

APPENDIX D DETAILED RESULTS

The optimal plans for each of the IRP scenarios are shown. The capacity required from each project in order to meet the annual peak is shown in each case.

Table 17. Base Case 0.0 (Kusile in)

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,689	347,830	252	-
2014	2543	0	0	0	0	0	0	2543	52113	43436	1966	25.66	23.52	-	290,540	206,850	341,505	252	-
2015	1988	0	0	0	0	0	0	1988	54101	44865	2594	27.98	23.48	-	300,425	244,060	327,011	259	-
2016	1355	0	0	0	0	0	0	1355	55456	45786	3007	29.63	24.52	-	310,243	280,709	326,392	264	-
2017	1446	0	0	0	0	0	0	1446	56902	47870	3420	28.01	22.54	-	320,751	314,878	330,861	272	-
2018	723	0	0	0	0	0	0	723	57625	49516	3420	25.01	19.82	-	332,381	346,282	341,701	286	-
2019	0	0	0	0	460	0	0	460	58085	51233	3420	21.48	16.57	-	344,726	378,543	346,415	297	1.95
2020	0	0	0	0	805	653	0	1458	59543	52719	3420	20.78	16.03	-	355,694	413,756	360,214	306	12.64
2021	-75	0	0	474	805	1023	0	2227	61770	54326	3420	21.34	16.72	-	365,826	451,476	368,262	313	22.47
2022	-1870	750	600	948	805	283	0	1516	63286	55734	3420	20.97	16.49	-	375,033	493,152	359,495	319	37.39
2023	-2280	750	600	711	0	0	1500	1281	64567	57097	3420	20.29	15.93	-	383,914	542,245	333,078	323	61.91
2024	-909	250	0	474	0	0	1500	1315	65882	58340	3420	19.96	15.70	-	392,880	581,161	321,490	330	39.47
2025	-1520	0	0	0	345	0	3000	1825	67707	60150	3420	19.35	15.24	-	404,358	625,387	300,861	337	65.21
2026	0	0	0	0	0	0	1500	1500	69207	61770	3420	18.61	14.63	-	415,281	657,853	303,450	348	31.87
2027	0	0	0	0	0	0	1500	1500	70707	63404	3420	17.88	14.02	-	426,196	688,775	306,068	359	31.87
2028	-2850	0	0	237	460	0	3750	1597	72304	64867	3420	17.67	13.91	-	436,761	730,641	277,801	365	83.15
2029	-1128	0	0	237	0	0	2250	1359	73663	66460	3420	16.85	13.20	-	445,888	762,702	266,200	372	49.32
2030	0	0	0	237	0	0	1500	1737	75400	67809	3420	17.10	13.52	-	454,357	789,481	266,721	381	33.39

Table 18. Base Case 0.1 (Kusile out)

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin capacity	Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,689	347,830	252	-
2014	2543	0	0	0	0	0	0	2543	52113	43436	1966	25.66	21.81	-	290,540	206,590	341,713	253	-
2015	542	0	0	0	0	0	0	542	52655	44865	2594	24.56	20.13	-	300,425	243,721	340,606	261	-
2016	632	0	0	0	0	0	0	632	53287	45786	3007	24.56	19.58	-	310,243	280,351	343,534	267	-
2017	0	250	0	948	0	0	0	1198	54485	47870	3420	22.57	17.27	-	320,751	320,924	355,130	277	10.63
2018	0	750	0	948	0	0	0	1698	56183	49516	3420	21.88	16.78	-	332,381	363,705	365,153	289	19.76
2019	0	0	0	0	805	1023	0	1828	58011	51233	3420	21.33	16.42	-	344,726	405,213	370,827	296	19.44
2020	0	0	0	0	805	936	0	1741	59752	52719	3420	21.20	16.44	-	355,694	442,556	386,714	305	15.07
2021	-75	750	600	0	690	0	0	1965	61717	54326	3420	21.24	16.62	-	365,826	483,658	389,664	316	27.81
2022	-1870	0	600	0	690	0	2250	1670	63387	55734	3420	21.17	16.67	-	375,033	535,814	365,346	321	61.92
2023	-2280	0	0	237	345	0	3000	1302	64689	57097	3420	20.52	16.15	-	383,914	587,710	338,592	325	66.72
2024	-909	0	0	0	0	0	2250	1341	66030	58340	3420	20.23	15.97	-	392,880	630,110	328,208	334	47.81
2025	-1520	0	0	0	115	0	3000	1595	67625	60150	3420	19.20	15.10	-	404,358	674,865	305,605	341	64.23
2026	0	0	0	0	115	0	1500	1615	69240	61770	3420	18.66	14.68	-	415,281	708,137	307,920	351	32.36
2027	0	0	0	237	0	0	1500	1737	70977	63404	3420	18.33	14.46	-	426,196	740,045	311,777	363	33.39
2028	-2850	0	0	948	0	0	3000	1098	72075	64867	3420	17.30	13.54	-	436,761	779,607	283,643	366	69.81
2029	-1128	0	0	474	0	0	2250	1596	73671	66460	3420	16.86	13.21	-	445,888	812,796	271,939	373	50.84
2030	0	0	0	0	0	0	1500	1500	75171	67809	3420	16.75	13.17	-	454,357	839,972	273,753	382	31.87

Table 19. Base Case 0.2 (Delay in Medupi and Kusile)

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	703	0	0	0	0	0	0	703	46247	40995	809	15.08	13.47	0.22	274,403	129,310	356,709	251	-
2013	2601	0	0	0	0	0	0	2601	48848	42416	1310	18.83	16.10	-	283,914	170,119	358,017	255	-
2014	1821	0	0	0	0	0	0	1821	50669	43436	1966	22.18	18.39	-	290,540	209,189	350,803	256	-
2015	1264	250	0	0	0	0	0	1514	52183	44865	2594	23.45	19.04	-	300,425	250,830	350,937	264	4.57
2016	632	0	0	0	0	0	0	632	52815	45786	3007	23.46	18.51	-	310,243	288,356	343,572	268	-
2017	2168	0	0	237	0	0	0	2405	55220	47870	3420	24.23	18.87	-	320,751	324,478	343,379	276	1.52
2018	723	0	0	237	0	0	0	960	56180	49516	3420	21.88	18.30	-	332,381	357,709	350,153	288	1.52
2019	1446	0	0	0	805	0	0	2251	58431	51233	3420	22.21	17.27	-	344,726	391,034	350,444	296	3.41
2020	723	0	0	0	575	0	0	1298	59729	52719	3420	21.16	16.40	-	355,694	422,011	357,831	307	2.44
2021	-75	0	0	0	805	1023	0	1753	61482	54326	3420	20.77	16.17	-	365,826	458,680	369,668	315	19.44
2022	-1870	750	600	948	805	936	0	2169	63651	55734	3420	21.67	17.16	-	375,033	503,475	354,802	318	46.02
2023	-2280	750	600	474	0	0	1500	1044	64695	57097	3420	20.53	16.16	-	383,914	551,623	332,037	324	59.79
2024	-909	0	0	474	0	0	1500	1065	65760	58340	3420	19.74	15.49	-	392,880	589,015	321,490	330	34.90
2025	-1520	0	0	237	0	0	3000	1717	67477	60150	3420	18.94	14.85	-	404,358	633,234	300,863	338	65.26
2026	0	0	0	0	0	0	1500	1500	68977	61770	3420	18.21	14.24	-	415,281	665,675	303,452	348	31.87
2027	0	0	0	0	0	0	1500	1500	70477	63404	3420	17.49	13.65	-	426,196	696,585	306,070	359	31.87
2028	-2850	0	0	0	805	0	3750	1705	72182	64867	3420	17.47	13.71	-	436,761	738,423	278,156	365	83.09
2029	-1128	0	0	237	0	0	2250	1359	73541	66460	3420	16.66	13.01	-	445,888	770,472	266,469	372	49.32
2030	0	0	0	0	0	0	1500	1500	75041	67809	3420	16.54	12.97	-	454,357	796,931	267,192	381	31.87

Table 20. Emissions 1.0

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Wind	Nuclear Fleet	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,689	347,830	252	-
2014	2543	0	0	0	0	0	0	0	0	2543	52113	43436	1966	25.66	23.52	-	290,540	206,850	341,505	252	-
2015	1988	0	0	0	0	0	0	0	0	1988	54101	44865	2594	27.98	23.48	-	300,425	244,060	327,011	259	-
2016	1355	0	0	0	0	0	0	0	0	1355	55456	45786	3007	29.63	24.52	-	310,243	280,709	326,392	264	-
2017	1446	0	0	0	0	0	1200	0	0	2646	58102	47870	3420	30.71	23.40	-	320,751	325,028	330,424	268	17.95
2018	723	0	0	948	0	0	1600	0	0	3271	61373	49516	3420	33.14	23.76	-	332,381	372,475	331,897	275	30.00
2019	0	0	0	948	0	740	1600	0	0	3288	64661	51233	3420	35.24	23.94	-	344,726	425,196	319,036	275	43.60
2020	0	0	0	948	0	370	1600	0	0	2918	67579	52719	3420	37.08	23.95	-	355,694	472,514	317,333	275	36.80
2021	-75	0	0	948	0	0	1600	0	0	2473	70052	54326	3420	37.61	22.82	-	365,826	516,670	317,085	275	30.00
2022	-1870	0	0	0	0	0	1400	1600	0	1130	71182	55734	3420	36.07	19.96	-	375,033	573,594	308,548	275	78.17
2023	-2280	0	0	0	805	0	0	1600	0	125	71307	57097	3420	32.85	17.22	-	383,914	620,892	303,971	274	60.63
2024	-909	0	0	0	805	283	1200	0	0	1379	72686	58340	3420	32.35	15.65	-	392,880	653,285	295,954	275	23.80
2025	-1520	0	0	0	805	283	0	1600	0	1168	73854	60150	3420	30.19	14.06	-	404,358	695,121	289,791	275	63.07
2026	0	0	0	0	230	0	0	1600	0	1830	75684	61770	3420	29.71	14.03	-	415,281	733,015	287,851	273	58.20
2027	0	250	0	474	690	0	800	0	0	2214	77898	63404	3420	29.86	13.73	-	426,196	760,364	283,339	275	22.49
2028	-2850	750	1200	0	0	0	0	1600	750	1450	79348	64867	3420	29.13	13.39	-	436,761	806,411	256,206	275	109.23
2029	-1128	750	0	0	115	0	0	1600	0	1337	80685	66460	3420	27.99	12.66	0	445,888	841,096	241,365	271	71.41
2030	0	0	0	0	690	283	0	0	0	973	81658	67809	3420	26.82	11.83	-	454,357	860,504	241,785	275	5.36

Table 21. Emissions 1.1 (Kusile out)

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Wind	Nuclear Fleet	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,689	347,830	252	-
2014	2543	0	0	0	0	0	0	0	0	2543	52113	43436	1966	25.66	21.81	-	290,540	206,590	341,713	253	-
2015	542	0	0	0	0	0	0	0	0	542	52655	44865	2594	24.56	20.13	-	300,425	243,721	340,606	261	-
2016	632	0	0	0	0	0	1400	0	0	2032	54687	45786	3007	27.84	20.63	-	310,243	292,939	339,264	263	20.95
2017	0	0	0	711	0	0	1600	0	0	2311	56998	47870	3420	28.23	18.36	-	320,751	343,102	345,535	269	28.49
2018	0	0	0	948	0	0	1600	0	0	2548	59546	49516	3420	29.18	17.37	-	332,381	390,784	354,302	275	30.00
2019	0	0	0	711	0	1110	1600	0	0	3421	62967	51233	3420	31.69	18.05	-	344,726	445,725	351,839	275	48.88
2020	0	0	0	948	575	0	1600	0	0	3123	66090	52719	3420	34.06	18.63	-	355,694	491,096	350,182	275	32.44
2021	-75	0	0	948	805	566	1600	0	0	3844	69934	54326	3420	37.38	20.29	-	365,826	538,150	341,588	275	38.28
2022	-1870	0	0	0	115	0	800	1600	0	645	70579	55734	3420	34.92	17.34	-	375,033	592,621	337,736	275	69.68
2023	-2280	750	0	0	575	0	0	1600	0	645	71224	57097	3420	32.69	15.61	-	383,914	645,226	329,010	274	73.36
2024	-909	750	0	0	805	0	600	0	0	1246	72470	58340	3420	31.95	14.55	-	392,880	679,784	313,825	275	26.09
2025	-1520	250	600	0	0	0	0	1600	750	1680	74150	60150	3420	30.71	13.88	-	404,358	730,669	290,717	273	88.91
2026	0	0	0	0	0	0	0	1600	0	1600	75750	61770	3420	29.82	13.47	0	415,281	769,248	290,696	272	57.22
2027	0	0	0	0	805	283	1000	0	0	2088	77838	63404	3420	29.76	12.76	-	426,196	797,055	288,699	275	20.81
2028	-2850	0	0	0	0	0	0	1600	3000	1750	79588	64867	3420	29.52	12.92	-	436,761	846,910	261,483	273	120.96
2029	-1128	0	0	0	0	0	0	1600	750	1222	80810	66460	3420	28.19	12.02	1	445,888	882,925	247,239	269	73.16
2030	0	0	0	0	805	0	0	0	0	805	81615	67809	3420	26.75	10.95	-	454,357	903,250	247,384	273	3.41

Table 22. Emissions 2.0

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Wind	Nuclear Fleet	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,689	347,830	252	-
2014	2543	0	0	0	0	0	0	0	0	2543	52113	43436	1966	25.66	23.52	-	290,540	206,850	341,505	252	-
2015	1988	0	0	0	0	0	0	0	0	1988	54101	44865	2594	27.98	23.48	-	300,425	244,060	327,011	259	-
2016	1355	0	0	0	0	0	0	0	0	1355	55456	45786	3007	29.63	24.52	-	310,243	280,709	326,392	264	-
2017	1446	0	0	0	0	0	0	0	0	1446	56902	47870	3420	28.01	22.54	-	320,751	314,878	330,861	272	-
2018	723	0	0	0	0	0	0	0	0	723	57625	49516	3420	25.01	19.82	-	332,381	346,282	341,701	286	-
2019	0	0	0	0	575	0	0	0	0	575	58200	51233	3420	21.72	16.80	-	344,726	378,773	346,414	296	2.44
2020	0	0	0	0	805	653	0	0	0	1458	59658	52719	3420	21.01	16.26	-	355,694	413,983	359,481	305	12.64
2021	-75	0	0	237	805	1023	0	0	0	1990	61648	54326	3420	21.10	16.49	-	365,826	451,041	369,552	313	20.96
2022	-1870	750	0	948	805	283	1600	0	0	2516	64164	55734	3420	22.65	16.12	-	375,033	497,317	360,838	315	49.55
2023	-2280	250	0	948	0	0	1600	1600	0	2118	66282	57097	3420	23.48	15.15	-	383,914	556,835	330,101	302	91.79
2024	-909	0	0	948	0	0	1600	1600	0	3239	69521	58340	3420	26.59	16.45	-	392,880	610,191	315,790	294	87.22
2025	-1520	0	0	711	0	0	1600	1600	0	2391	71912	60150	3420	26.76	15.10	-	404,358	660,475	277,549	275	85.71
2026	0	0	0	0	0	0	1600	1600	0	3200	75112	61770	3420	28.73	15.54	-	415,281	705,297	279,917	275	81.16
2027	0	0	0	474	115	0	1600	0	0	2189	77301	63404	3420	28.87	14.28	-	426,196	734,485	274,581	275	27.46
2028	-2850	750	1200	0	230	0	400	1600	0	1330	78631	64867	3420	27.96	13.31	-	436,761	778,629	252,124	275	100.25
2029	-1128	0	0	0	0	0	0	1600	750	1222	79853	66460	3420	26.67	12.41	-	445,888	813,912	241,916	272	73.16
2030	0	0	0	0	805	0	800	0	0	1605	81458	67809	3420	26.51	11.73	-	454,357	835,491	241,091	275	15.38

Table 23. Emissions 2.1 (Kusile out)

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Wind	Nuclear Fleet	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,689	347,830	252	-
2014	2543	0	0	0	0	0	0	0	0	2543	52113	43436	1966	25.66	21.81	-	290,540	206,590	341,713	253	-
2015	542	0	0	0	0	0	0	0	0	542	52655	44865	2594	24.56	20.13	-	300,425	243,721	340,606	261	-
2016	632	0	0	0	0	0	0	0	0	632	53287	45786	3007	24.56	19.58	-	310,243	280,351	343,534	267	-
2017	0	0	0	948	0	0	0	0	0	948	54235	47870	3420	22.01	17.27	-	320,751	320,931	355,279	278	10.63
2018	0	750	0	711	0	0	0	0	0	1461	55696	49516	3420	20.83	15.76	-	332,381	360,554	369,827	290	13.68
2019	0	0	0	0	805	1023	0	0	0	1828	57524	51233	3420	20.31	15.43	-	344,726	402,372	375,349	297	19.44
2020	0	0	0	0	805	936	0	0	0	1741	59265	52719	3420	20.22	15.97	-	355,694	442,002	385,196	305	19.64
2021	-75	750	0	0	690	0	1600	0	0	2965	62230	54326	3420	22.24	16.03	-	365,826	488,353	389,522	312	40.57
2022	-1870	0	1200	0	690	0	1600	1600	0	3220	65450	55734	3420	25.11	16.99	-	375,033	556,601	353,235	301	106.46
2023	-2280	250	0	948	0	0	1600	1600	750	2868	68318	57097	3420	27.28	16.90	-	383,914	619,801	323,923	289	103.16
2024	-909	0	0	948	0	0	1600	0	0	1639	69957	58340	3420	27.38	15.33	-	392,880	655,496	316,621	289	30.00
2025	-1520	0	0	711	460	0	1600	1600	0	2851	72808	60150	3420	28.34	14.80	-	404,358	706,826	284,836	275	87.66
2026	0	0	0	0	0	0	1600	1600	0	3200	76008	61770	3420	30.26	15.24	-	415,281	752,117	289,719	275	81.16
2027	0	0	0	0	460	0	1600	0	0	2060	78068	63404	3420	30.15	13.79	-	426,196	781,269	285,229	275	25.89
2028	-2850	0	0	0	0	0	0	1600	3000	1750	79818	64867	3420	29.90	13.92	-	436,761	831,030	258,205	275	120.96
2029	-1128	0	0	0	0	0	0	1600	1500	1972	81790	66460	3420	29.74	14.17	-	445,888	870,251	244,361	273	89.09
2030	0	0	0	0	805	0	400	0	0	1205	82995	67809	3420	28.90	13.25	-	454,357	891,015	243,877	275	9.40

Table 24. Emissions 3.0

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Wind	Nuclear Fleet	CSP	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,689	347,830	252	-
2014	2543	0	0	0	0	0	0	0	0	2543	52113	43436	1966	25.66	23.52	-	290,540	206,844	341,494	252	-
2015	1988	0	0	0	0	0	1600	0	0	3588	55701	44865	2594	31.77	24.70	-	300,425	259,821	324,217	254	23.94
2016	1355	0	0	0	0	0	1600	0	0	2955	58656	45786	3007	37.11	26.92	-	310,243	311,093	325,526	255	23.94
2017	1446	0	0	948	0	0	1600	0	1500	5494	64150	47870	3420	44.32	29.69	-	320,751	410,634	331,122	265	114.28
2018	723	0	0	948	0	0	1600	0	3125	6396	70546	49516	3420	53.04	33.12	-	332,381	551,328	320,855	261	205.57
2019	0	0	0	948	805	0	1600	0	3125	6478	77024	51233	3420	61.09	36.28	-	344,726	686,055	310,920	256	208.99
2020	0	0	0	948	805	1110	1600	0	3125	7588	84612	52719	3420	71.63	42.06	-	355,694	832,231	251,137	220	229.38
2021	-75	0	0	474	805	0	1600	0	375	3179	87791	54326	3420	72.46	41.36	-	365,826	910,046	248,837	220	51.45
2022	-1870	0	0	0	0	0	1600	1600	0	1330	89121	55734	3420	70.36	38.14	-	375,033	971,083	245,914	220	81.16
2023	-2280	0	0	0	0	0	200	1600	0	-480	88641	57097	3420	65.14	33.61	-	383,914	1,019,413	250,447	220	60.21
2024	-909	0	0	0	0	0	1600	0	0	691	89332	58340	3420	62.66	29.98	-	392,880	1,053,142	243,538	220	23.94
2025	-1520	0	0	0	0	0	0	1600	0	80	89412	60150	3420	57.61	26.07	-	404,358	1,093,535	238,351	220	57.22
2026	0	0	0	0	805	0	400	1600	0	2805	92217	61770	3420	58.04	26.90	-	415,281	1,134,046	242,436	220	66.62
2027	0	0	0	0	805	0	1400	0	0	2205	94422	63404	3420	57.41	25.59	-	426,196	1,162,091	228,833	220	24.36
2028	-2850	0	0	0	805	0	0	1600	0	-445	93977	64867	3420	52.94	21.95	-	436,761	1,195,990	218,252	220	60.63
2029	-1128	0	0	0	805	0	400	1600	0	1677	95654	66460	3420	51.74	21.13	2	445,888	1,229,179	216,538	220	66.62
2030	0	0	0	0	805	0	800	0	0	1605	97259	67809	3420	51.05	20.27	-	454,357	1,250,053	218,970	220	15.38

Table 25. Emissions 3.1

	Committed	Coal FBC	Gas CCGT	OCGT	Import Hydro	Wind	Nuclear Fleet	CSP	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,689	347,830	252	-
2014	2543	0	0	0	0	0	0	0	2543	52113	43436	1966	25.66	21.81	-	290,540	206,590	341,713	253	-
2015	542	0	0	0	0	1600	0	0	2142	54255	44865	2594	28.35	21.35	-	300,425	259,322	332,430	256	23.94
2016	632	0	0	0	0	1600	0	0	2232	56487	45786	3007	32.04	21.99	-	310,243	310,191	329,870	258	23.94
2017	0	0	948	0	0	1600	0	1375	3923	60410	47870	3420	35.90	21.67	-	320,751	404,866	331,716	257	107.25
2018	0	0	948	0	0	1600	0	3125	5673	66083	49516	3420	43.36	23.86	-	332,381	544,327	335,070	254	205.57
2019	0	0	948	805	1023	1600	0	3125	7501	73584	51233	3420	53.90	29.42	-	344,726	685,375	327,097	247	225.02
2020	0	0	948	805	936	1600	0	3125	7414	80998	52719	3420	64.30	35.05	-	355,694	829,396	263,280	220	220.65
2021	-75	0	474	805	0	1600	0	0	2804	83802	54326	3420	64.62	34.21	-	365,826	902,000	252,181	220	30.38
2022	-1870	0	0	805	0	1600	1600	0	2135	85937	55734	3420	64.27	32.68	-	375,033	964,850	274,297	220	84.57
2023	-2280	0	0	0	0	1600	1600	0	920	86857	57097	3420	61.82	29.12	-	383,914	1,020,148	273,368	220	81.16
2024	-909	0	0	0	0	1600	0	0	691	87548	58340	3420	59.41	25.59	-	392,880	1,053,778	264,328	220	23.94
2025	-1520	0	0	230	0	1200	1600	0	1510	89058	60150	3420	56.99	22.90	0	404,358	1,099,538	261,508	220	76.15
2026	0	0	0	805	0	400	1600	0	2805	91863	61770	3420	57.43	23.81	1	415,281	1,139,645	260,747	220	66.62
2027	0	0	0	805	0	1600	0	0	2405	94268	63404	3420	57.16	22.69	-	426,196	1,167,907	258,510	220	27.35
2028	-2850	0	0	805	0	0	1600	0	-445	93823	64867	3420	52.69	19.12	-	436,761	1,202,008	256,587	220	60.63
2029	-1128	250	0	805	0	0	1600	0	1277	95100	66460	3420	50.86	18.55	6	445,888	1,235,289	243,827	216	65.20
2030	0	250	0	805	0	800	0	0	2105	97205	67809	3420	50.97	18.12	6	454,357	1,257,457	245,613	220	19.95

Table 26. Carbon Tax 0.0

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Wind	Nuclear Fleet	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,144	336,986	237	-
2011	1009	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,480	349,508	243	-
2012	1425	0	0	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,943	350,347	250	-
2013	2601	0	0	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,796	348,884	252	-
2014	2543	0	0	0	0	0	0	0	0	2543	52113	43436	1966	25.66	23.52	-	290,540	206,991	342,094	252	-
2015	1988	0	0	0	0	0	0	0	0	1988	54101	44865	2594	27.98	23.48	-	300,425	244,286	325,753	258	-
2016	1355	0	0	0	0	0	0	0	0	1355	55456	45786	3007	29.63	24.52	-	310,243	281,090	325,941	262	-
2017	1446	0	0	0	0	0	0	0	0	1446	56902	47870	3420	28.01	22.54	-	320,751	315,275	331,571	271	-
2018	723	0	0	0	0	0	0	0	0	723	57625	49516	3420	25.01	19.82	-	332,381	346,875	342,090	284	-
2019	0	0	0	0	690	1110	0	0	0	1800	59425	51233	3420	24.29	19.29	-	344,726	389,131	332,002	288	23.32
2020	0	0	0	0	575	283	1600	0	0	2458	61883	52719	3420	25.53	18.53	-	355,694	431,146	342,493	294	28.81
2021	-75	0	0	0	460	283	1600	0	0	2268	64151	54326	3420	26.02	17.17	-	365,826	470,793	354,372	302	28.32
2022	-1870	0	0	0	805	0	1600	1600	0	2135	66286	55734	3420	26.71	16.08	-	375,033	529,377	336,477	293	84.57
2023	-2280	0	0	711	575	0	1600	1600	0	2206	68492	57097	3420	27.60	15.27	-	383,914	586,151	314,969	284	88.15
2024	-909	0	0	948	230	283	1600	0	0	2152	70644	58340	3420	28.63	14.64	-	392,880	621,666	313,255	286	33.41
2025	-1520	0	0	948	0	0	1600	1600	0	2628	73272	60150	3420	29.16	13.75	-	404,358	671,141	289,593	275	87.22
2026	0	0	0	0	0	0	1600	1600	0	3200	76472	61770	3420	31.06	14.23	-	415,281	715,339	283,735	271	81.16
2027	0	0	0	948	0	0	1600	0	0	2548	79020	63404	3420	31.74	13.59	0	426,196	743,944	287,897	275	30.00
2028	-2850	750	0	711	690	0	1600	1600	0	2501	81521	64867	3420	32.67	13.22	-	436,761	788,574	255,199	262	102.33
2029	-1128	250	0	0	230	0	1600	1600	0	2552	84073	66460	3420	33.37	12.72	1	445,888	826,849	238,257	254	86.70
2030	0	750	0	0	0	0	1600	0	0	2350	86423	67809	3420	34.22	12.35	0	454,357	852,377	238,561	260	37.64

Table 27. Carbon Tax 0.1

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Wind	Nuclear Fleet	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,144	336,986	237	-
2011	1009	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,480	349,508	243	-
2012	1425	0	0	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,943	350,347	250	-
2013	2601	0	0	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,796	348,884	252	-
2014	2543	0	0	0	0	0	0	0	0	2543	52113	43436	1966	25.66	21.81	-	290,540	206,770	343,493	253	-
2015	542	0	0	0	0	0	0	0	0	542	52655	44865	2594	24.56	20.13	-	300,425	243,973	335,139	260	-
2016	632	0	0	0	0	0	0	0	0	632	53287	45786	3007	24.56	19.58	-	310,243	280,622	340,966	267	-
2017	0	0	0	948	0	0	1600	0	0	2548	55835	47870	3420	25.61	17.87	-	320,751	331,915	350,621	272	30.00
2018	0	0	0	948	0	0	1600	0	0	2548	58383	49516	3420	26.66	16.90	-	332,381	379,607	363,118	280	30.00
2019	0	0	0	0	805	1110	1600	0	0	3515	61898	51233	3420	29.46	17.78	-	344,726	434,053	356,459	279	47.75
2020	0	0	0	0	805	283	1600	0	0	2688	64586	52719	3420	31.01	17.52	-	355,694	477,052	363,889	286	29.78
2021	-75	0	0	237	805	0	1600	0	0	2567	67153	54326	3420	31.91	16.76	-	365,826	517,869	375,852	292	28.87
2022	-1870	0	0	474	575	283	1600	1600	0	2662	69815	55734	3420	33.45	16.67	0	375,033	579,388	351,030	281	89.06
2023	-2280	250	0	948	0	0	1600	1600	0	2118	71933	57097	3420	34.01	15.68	-	383,914	638,794	323,326	268	91.79
2024	-909	750	0	711	0	283	1600	0	0	2435	74368	58340	3420	35.41	15.54	-	392,880	678,957	314,781	271	44.62
2025	-1520	500	0	0	115	0	1600	1600	0	2295	76663	60150	3420	35.14	14.05	-	404,358	730,261	289,238	262	90.78
2026	0	0	0	0	0	0	1600	1600	0	3200	79863	61770	3420	36.87	14.52	1	415,281	774,999	287,094	259	81.16
2027	0	250	0	0	575	0	1600	0	0	2425	82288	63404	3420	37.18	13.68	1	426,196	804,312	288,875	264	30.94
2028	-2850	0	1200	0	690	0	1600	1600	0	2240	84528	64867	3420	37.56	12.89	-	436,761	850,277	255,193	252	106.46
2029	-1128	0	0	0	345	0	1600	1600	0	2417	86945	66460	3420	37.92	12.19	4	445,888	888,075	239,690	244	82.62
2030	0	0	0	0	115	0	1600	0	750	2465	89410	67809	3420	38.86	12.00	3	454,357	914,638	240,992	249	40.36

Table 28. Regional development 0.0

	Committed	Coal FBC	Import Coal	Import Gas	Gas CCGT	OCGT	Import Hydro	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,689	347,830	252	-
2014	2543	0	0	0	0	0	0	0	2543	52113	43436	1966	25.66	23.52	-	290,540	206,850	341,505	252	-
2015	1988	0	0	0	0	0	0	0	1988	54101	44865	2594	27.98	23.48	-	300,425	244,060	327,011	259	-
2016	1355	0	0	0	0	0	0	0	1355	55456	45786	3007	29.63	24.52	-	310,243	280,709	326,392	264	-
2017	1446	0	0	0	0	0	0	0	1446	56902	47870	3420	28.01	22.54	-	320,751	314,878	330,861	272	-
2018	723	0	0	0	0	0	0	0	723	57625	49516	3420	25.01	19.82	-	332,381	346,282	341,701	286	-
2019	0	0	0	0	0	575	0	0	575	58200	51233	3420	21.72	16.80	-	344,726	378,773	346,414	296	2.44
2020	0	0	0	0	0	805	480	0	1285	59485	52719	3420	20.66	15.92	-	355,694	411,154	360,645	306	6.08
2021	-75	0	0	0	237	805	1183	0	2150	61635	54326	3420	21.08	16.46	-	365,826	449,227	369,814	313	23.38
2022	-1870	750	0	0	948	805	1686	0	2319	63954	55734	3420	22.25	17.73	-	375,033	491,263	358,187	314	39.64
2023	-2280	750	2200	0	474	690	0	0	1834	65788	57097	3420	22.56	18.14	-	383,914	539,596	330,000	319	61.67
2024	-909	250	0	0	237	0	0	1500	1078	66866	58340	3420	21.75	17.45	-	392,880	577,374	318,869	325	37.95
2025	-1520	0	0	0	0	0	0	3000	1480	68346	60150	3420	20.48	16.34	-	404,358	620,605	298,252	333	63.74
2026	0	0	0	0	0	230	0	1500	1730	70076	61770	3420	20.09	16.08	-	415,281	652,813	300,788	344	32.85
2027	0	0	0	0	0	0	0	1500	1500	71576	63404	3420	19.33	15.43	-	426,196	683,229	303,455	355	31.87
2028	-2850	0	0	0	237	805	0	3750	1942	73518	64867	3420	19.64	15.84	-	436,761	724,996	274,127	360	84.61
2029	-1128	0	0	0	237	115	0	2250	1474	74992	66460	3420	18.96	15.26	-	445,888	756,729	263,087	367	49.81
2030	0	0	0	0	237	0	0	1500	1737	76729	67809	3420	19.17	15.54	-	454,357	783,120	262,911	376	33.39

Table 29. Regional development 0.1

	Committed	Coal FBC	Import Coal	Import Gas	Gas CCGT	OCGT	Import Hydro	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.84	-	283,914	168,689	347,830	252	-
2014	2543	0	0	0	0	0	0	0	2543	52113	43436	1966	25.66	21.81	-	290,540	206,590	341,713	253	-
2015	542	0	0	0	0	0	0	0	542	52655	44865	2594	24.56	20.13	-	300,425	243,721	340,606	261	-
2016	632	0	0	0	0	0	0	0	632	53287	45786	3007	24.56	19.58	-	310,243	280,351	343,534	267	-
2017	0	0	0	0	948	0	120	0	1068	54355	47870	3420	22.28	16.98	-	320,751	319,003	357,352	277	7.20
2018	0	500	0	0	948	0	520	0	1968	56323	49516	3420	22.19	17.07	-	332,381	361,266	367,487	287	19.16
2019	0	0	0	0	0	805	1023	0	1828	58151	51233	3420	21.62	16.70	-	344,726	402,611	373,978	294	19.44
2020	0	250	0	0	0	805	936	0	1991	60142	52719	3420	21.99	17.21	-	355,694	441,711	386,503	303	19.64
2021	-75	750	600	0	0	460	0	0	1735	61877	54326	3420	21.55	16.93	-	365,826	482,176	389,596	314	26.84
2022	-1870	250	1600	0	0	805	750	750	2285	64162	55734	3420	22.65	18.12	-	375,033	532,798	359,561	316	59.54
2023	-2280	0	0	0	0	345	0	3000	1065	65227	57097	3420	21.52	17.13	-	383,914	583,498	335,981	321	65.21
2024	-909	0	0	0	0	115	0	2250	1456	66683	58340	3420	21.42	17.13	-	392,880	625,464	324,424	329	48.30
2025	-1520	0	0	0	0	575	0	3000	2055	68738	60150	3420	21.17	17.01	-	404,358	670,256	300,978	336	66.18
2026	0	0	0	0	0	0	0	1500	1500	70238	61770	3420	20.37	16.35	-	415,281	702,908	303,540	346	31.87
2027	0	0	0	0	0	0	0	1500	1500	71738	63404	3420	19.60	15.70	-	426,196	733,942	307,513	358	31.87
2028	-2850	0	0	0	474	460	0	3000	1084	72822	64867	3420	18.51	14.73	-	436,761	772,814	281,026	362	68.73
2029	-1128	0	0	0	474	0	0	2250	1596	74418	66460	3420	18.05	14.37	-	445,888	805,588	269,328	368	50.84
2030	0	0	0	0	0	0	0	1500	1500	75918	67809	3420	17.91	14.31	-	454,357	832,388	270,782	378	31.87

Table 30. Enhanced Demand Side Management 0.0

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	1425	46969	40995	1059	17.61	15.67	-	274,403	128,819	349,386	249	-
2013	2601	0	0	0	0	0	0	2601	49570	42416	1822	22.11	18.70	-	283,914	168,406	345,486	250	-
2014	2543	0	0	0	0	0	0	2543	52113	43436	2987	28.84	25.30	-	290,540	206,341	341,210	248	-
2015	1988	0	0	0	0	0	0	1988	54101	44865	4128	32.80	26.10	-	300,425	243,228	324,075	252	-
2016	1355	0	0	0	0	0	0	1355	55456	45786	4539	34.45	27.11	-	310,243	279,591	325,855	257	-
2017	1446	0	0	0	0	0	0	1446	56902	47870	4954	32.59	24.98	-	320,751	313,505	330,096	266	-
2018	723	0	0	0	0	0	0	723	57625	49516	4954	29.32	22.12	-	332,381	344,579	333,656	281	-
2019	0	0	0	0	805	0	0	805	58430	51233	4954	26.26	19.45	-	344,726	377,106	334,966	290	3.41
2020	0	0	0	0	805	0	0	805	59235	52719	4954	24.01	17.50	-	355,694	407,974	354,603	302	3.41
2021	-75	0	0	0	805	1023	0	1753	60988	54326	4954	23.53	17.24	-	365,826	444,098	364,178	310	19.44
2022	-1870	750	600	948	690	936	0	2054	63042	55734	4954	24.15	18.00	-	375,033	488,207	349,074	313	45.54
2023	-2280	750	600	948	805	0	750	1573	64615	57097	4954	23.92	17.94	-	383,914	532,663	331,778	318	50.30
2024	-909	250	0	237	0	0	1500	1078	65693	58340	4954	23.05	17.24	-	392,880	570,655	320,189	324	37.95
2025	-1520	0	0	0	0	0	3000	1480	67173	60150	4954	21.70	16.12	-	404,358	614,075	299,568	332	63.74
2026	0	0	0	0	0	0	1500	1500	68673	61770	4954	20.87	15.47	-	415,281	646,186	302,155	343	31.87
2027	0	0	0	0	0	0	2250	2250	70923	63404	4954	21.34	16.07	-	426,196	680,702	301,755	355	47.81
2028	-2850	0	0	474	460	0	3000	1084	72007	64867	4954	20.19	15.08	-	436,761	718,736	276,661	360	68.73
2029	-1128	0	0	0	115	0	2250	1237	73244	66460	4954	19.08	14.14	-	445,888	750,275	265,172	366	48.30
2030	0	0	0	0	230	0	1500	1730	74974	67809	4954	19.28	14.43	-	454,357	776,661	266,254	376	32.85

Table 31. Enhanced Demand Side Management 0.1

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	1425	0	0	0	0	0	0	1425	46969	40995	1059	17.61	15.67	-	274,403	128,819	349,386	249	-
2013	2601	0	0	0	0	0	0	2601	49570	42416	1822	22.11	18.70	-	283,914	168,406	345,486	250	-
2014	2543	0	0	0	0	0	0	2543	52113	43436	2987	28.84	23.56	-	290,540	206,085	341,450	249	-
2015	542	0	0	0	0	0	0	542	52655	44865	4128	29.25	22.68	-	300,425	242,713	330,727	255	-
2016	632	0	0	0	0	0	0	632	53287	45786	4539	29.19	22.08	-	310,243	278,837	337,613	262	-
2017	0	250	0	948	0	0	0	1198	54485	47870	4954	26.96	19.61	-	320,751	318,896	346,008	271	10.63
2018	0	750	0	948	0	0	0	1698	56183	49516	4954	26.08	19.03	-	332,381	361,175	356,147	283	19.76
2019	0	0	0	0	805	1023	0	1828	58011	51233	4954	25.35	18.58	-	344,726	402,121	358,012	289	19.44
2020	0	0	0	0	805	936	0	1741	59752	52719	4954	25.10	18.54	-	355,694	438,786	374,476	298	15.07
2021	-75	750	0	237	805	0	0	1717	61469	54326	4954	24.50	18.17	-	365,826	475,524	387,158	310	18.63
2022	-1870	0	1200	0	805	0	1500	1635	63104	55734	4954	24.27	18.12	-	375,033	525,556	362,887	315	57.66
2023	-2280	0	0	0	575	0	3000	1295	64399	57097	4954	23.51	17.54	-	383,914	576,773	337,295	320	66.18
2024	-909	0	0	0	0	0	2250	1341	65740	58340	4954	23.14	17.32	-	392,880	618,709	326,908	329	47.81
2025	-1520	0	0	0	345	0	3000	1825	67565	60150	4954	22.41	16.80	-	404,358	663,323	304,063	336	65.21
2026	0	0	0	0	115	0	1500	1615	69180	61770	4954	21.76	16.33	-	415,281	696,200	306,090	346	32.36
2027	0	0	0	0	0	0	1500	1500	70680	63404	4954	20.92	15.67	-	426,196	727,351	310,626	358	31.87
2028	-2850	0	0	948	115	0	3000	1213	71893	64867	4954	19.99	14.89	-	436,761	766,688	282,341	361	70.30
2029	-1128	0	0	474	0	0	2250	1596	73489	66460	4954	19.48	14.53	-	445,888	799,562	270,641	367	50.84
2030	0	0	0	0	0	0	1500	1500	74989	67809	4954	19.31	14.46	-	454,357	826,429	272,628	377	31.87

Table 32. Balanced Scenario

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Wind	Nuclear Fleet	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions	Capital expenditure (at date of commercial operation)
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT	Rbn
2010	640	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	-	259,685	44,138	336,420	237	-
2011	1009	0	0	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	-	266,681	87,467	349,613	243	-
2012	703	0	0	0	0	0	0	0	0	703	46247	40995	809	15.08	15.25	-	274,403	128,921	350,510	250	-
2013	2601	0	0	0	0	0	0	0	0	2601	48848	42416	1310	18.83	16.10	-	283,914	168,999	350,208	253	-
2014	1821	0	0	0	0	0	200	0	0	2021	50869	43436	1966	22.66	23.68	-	290,540	209,286	341,515	251	2.99
2015	1264	0	0	0	0	0	400	0	0	1664	52533	44865	2594	24.28	23.93	-	300,425	250,426	324,482	257	5.98
2016	632	0	0	0	0	0	800	0	0	1432	53965	45786	3007	26.15	25.57	-	310,243	294,325	326,187	261	11.97
2017	2168	0	0	0	0	0	800	0	0	2968	56933	47870	3420	28.08	19.39	-	320,751	336,017	337,415	270	11.97
2018	723	0	0	0	0	0	800	0	0	1523	58456	49516	3420	26.81	18.86	-	332,381	374,208	343,296	280	11.97
2019	1446	0	0	0	0	0	800	0	0	2246	60702	51233	3420	26.96	16.71	-	344,726	411,135	337,736	287	11.97
2020	723	0	0	0	575	0	800	0	0	2098	62800	52719	3420	27.39	16.37	-	355,694	446,855	343,273	295	14.41
2021	-75	0	0	237	805	0	800	0	0	1767	64567	54326	3420	26.83	15.15	-	365,826	482,121	358,681	305	16.90
2022	-1870	250	0	948	805	1110	800	0	0	2043	66610	55734	3420	27.33	14.94	0	375,033	526,618	345,092	303	46.41
2023	-2280	0	0	711	805	566	800	1600	0	2202	68812	57097	3420	28.20	15.12	-	383,914	581,802	329,844	295	82.01
2024	-909	0	0	474	230	0	600	1600	0	1995	70807	58340	3420	28.93	15.41	-	392,880	629,275	315,583	288	70.20
2025	-1520	0	0	711	0	0	1600	1600	0	2391	73198	60150	3420	29.03	14.08	-	404,358	678,476	285,251	275	85.71
2026	0	0	0	0	0	0	400	1600	0	2000	75198	61770	3420	28.87	13.89	-	415,281	717,888	288,015	275	63.21
2027	0	0	0	948	230	0	1400	0	0	2578	77776	63404	3420	29.66	13.53	-	426,196	746,887	283,541	275	27.99
2028	-2850	750	0	0	0	0	0	1600	1500	1000	78776	64867	3420	28.20	12.48	-	436,761	791,663	258,267	274	102.79
2029	-1128	750	0	0	115	0	0	1600	750	2087	80863	66460	3420	28.27	12.94	-	445,888	829,800	240,756	272	87.34
2030	0	0	0	237	575	0	0	0	0	812	81675	67809	3420	26.85	11.86	-	454,357	848,906	241,943	275	3.95

Table 33. Revised Balanced Scenario

	Current programmes											New build options															
	RTS Capacity	Medupi	Kusile	Ingula	DOE OCGT IPP	Co-gen, own build	Wind	CSP	Landfill, hydro	Sere	Decommissioning	Coal FBC	Import Coal	Co-gen, own build	Gas CCGT	OCGT	Import Hydro	Wind	Solar PV, CSP	Solar CSP, Solar PV, Landfill,	Nuclear Fleet	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
2010	380	0	0	0	0	260	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	640	44535	38885	252	15.28
2011	679	0	0	0	0	130	200	0	0	0	0	0	0	103	0	0	0	0	0	0	0	0	1112	45647	39956	494	15.41
2012	303	0	0	0	0	0	200	0	100	100	0	0	0	0	0	0	0	0	0	0	0	0	703	46350	40995	809	15.08
2013	101	722	0	333	1020	0	300	0	25	0	0	0	0	124	0	0	0	0	0	0	0	0	2625	48975	42416	1310	18.59
2014	0	722	0	999	0	0	0	100	0	0	0	0	0	426	0	0	0	200	0	0	0	0	2447	51422	43436	1966	22.42
2015	0	1444	0	0	0	0	0	100	0	0	-180	0	0	600	0	0	0	400	0	0	0	0	2364	53786	44865	2594	24.28
2016	0	722	0	0	0	0	0	0	0	0	-90	0	0	0	0	0	0	800	100	0	0	0	1532	55318	45786	3007	26.38
2017	0	722	1446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	800	100	0	0	0	3068	58386	47870	3420	28.53
2018	0	0	723	0	0	0	0	0	0	0	0	0	0	0	0	0	0	800	100	0	0	0	1623	60009	49516	3420	27.47
2019	0	0	1446	0	0	0	0	0	0	0	0	0	0	0	474	0	0	800	100	0	0	0	2820	62829	51233	3420	28.79
2020	0	0	723	0	0	0	0	0	0	0	0	0	0	0	711	0	360	0	0	800	0	0	2594	65423	52719	3420	30.17
2021	0	0	0	0	0	0	0	0	0	0	-75	0	0	0	711	0	750	0	0	800	0	0	2186	67609	54326	3420	30.35
2022	0	0	0	0	0	0	0	0	0	0	-1870	0	0	0	0	805	1110	0	0	800	0	0	845	68454	55734	3420	28.46
2023	0	0	0	0	0	0	0	0	0	0	-2280	0	0	0	0	805	1129	0	0	800	1600	0	2054	70508	57097	3420	29.02
2024	0	0	0	0	0	0	0	0	0	0	-909	0	0	0	0	575	0	0	0	800	1600	0	2066	72574	58340	3420	29.86
2025	0	0	0	0	0	0	0	0	0	0	-1520	0	0	0	0	805	0	0	0	1400	1600	0	2285	74859	60150	3420	29.75
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600	1600	0	2200	77059	61770	3420	29.91
2027	0	0	0	0	0	0	0	0	0	0	0	250	500	0	0	805	0	0	0	1200	0	0	2755	79814	63404	3420	30.97
2028	0	0	0	0	0	0	0	0	0	0	-2850	750	500	0	0	805	0	0	0	0	1600	750	1555	81369	64867	3420	30.38
2029	0	0	0	0	0	0	0	0	0	0	-1128	750	0	0	0	805	0	0	0	0	1600	0	2027	83396	66460	3420	30.30
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	345	0	0	0	0	0	1500	1845	85241	67809	3420	30.44

Table 34. COUE sensitivity: R10/kWh

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast	PV Total cost (cumulative)	Water	Total CO_2 emissions
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh	Rm	ML	MT
2010	640	0	0	0	0	0	0	640	44535	38885	252	15.28	15.18	25.91	259,685		323,148	235
2011	1009	0	0	0	0	0	0	1009	45544	39956	494	15.41	14.74	9.30	266,681		329,642	240
2012	1425	0	0	0	0	0	0	1425	46969	40995	809	16.88	15.25	16.79	274,403		338,298	247
2013	2601	0	0	0	0	0	0	2601	49570	42416	1310	20.59	17.72	79.49	283,914		337,258	250
2014	2543	0	0	0	0	0	0	2543	52113	43436	1966	25.66	23.41	3.18	290,540		334,003	252
2015	1988	0	0	0	0	0	0	1988	54101	44865	2594	27.98	23.36	0.68	300,425		335,301	260
2016	1355	0	0	0	0	0	0	1355	55456	45786	3007	29.63	24.40	1.00	310,243		335,693	266
2017	1446	0	0	0	0	0	0	1446	56902	47870	3420	28.01	22.43	-	320,751		340,432	274
2018	723	0	0	0	0	0	0	723	57625	49516	3420	25.01	19.71	0.77	332,381		345,526	286
2019	0	0	0	0	0	0	0	0	57625	51233	3420	20.52	15.53	25.42	344,726		353,796	296
2020	0	0	0	474	0	653	0	1127	58752	52719	3420	19.18	14.37	15.53	355,694		360,513	304
2021	-75	0	0	948	115	1023	0	2011	60763	54326	3420	19.36	14.70	46.04	365,826		364,379	310
2022	-1870	750	0	948	0	283	0	111	60874	55734	3420	16.36	11.90	36.79	375,033		348,358	314
2023	-2280	750	1200	948	0	0	750	1368	62242	57097	3420	15.96	11.62	69.28	383,914		324,887	319
2024	-909	250	0	948	0	0	1500	1789	64031	58340	3420	16.59	12.33	24.03	392,880		320,123	327
2025	-1520	0	0	0	115	0	3000	1595	65626	60150	3420	15.68	11.58	26.15	404,358		302,229	334
2026	0	0	0	0	230	0	1500	1730	67356	61770	3420	15.43	11.45	28.18	415,281		306,949	345
2027	0	0	0	0	345	0	1500	1845	69201	63404	3420	15.37	11.49	21.78	426,196		310,848	356
2028	-2850	0	0	0	115	0	3750	1015	70216	64867	3420	14.27	10.50	48.52	436,761		282,567	362
2029	-1128	0	0	0	0	0	3000	1872	72088	66460	3420	14.35	10.68	32.57	445,888		271,142	370
2030	0	0	0	0	460	0	750	1210	73298	67809	3420	13.84	10.25	48.70	454,357		272,949	378

Table 35. High Demand forecast sensitivity on Base Case

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh
2010	640	0	0	0	0	0	0	640	44535	39216	252	14.30	14.20	759.05	261,767
2011	1009	0	0	0	0	0	0	1009	45544	40629	494	13.48	12.83	1,020.95	270,972
2012	1425	0	0	0	0	0	0	1425	46969	42027	809	13.95	12.38	809.05	281,022
2013	2601	0	0	0	0	0	0	2601	49570	43839	1310	16.56	13.94	461.60	293,036
2014	2543	0	0	0	0	0	0	2543	52113	45255	1966	20.38	18.42	67.04	302,200
2015	1988	0	0	0	0	0	0	1988	54101	47124	2594	21.49	17.35	38.71	314,927
2016	1355	0	0	0	0	0	0	1355	55456	48479	3007	21.96	17.33	20.44	327,752
2017	1446	0	0	948	0	0	0	2394	57850	51090	3420	21.36	16.43	26.81	341,505
2018	723	250	0	948	0	0	0	1921	59771	53276	3420	19.89	15.21	20.37	356,713
2019	0	0	0	474	805	1110	0	2389	62160	55573	3420	19.19	14.73	15.56	372,931
2020	0	750	0	948	690	566	0	2954	65114	57649	3420	20.07	15.76	9.91	387,872
2021	-75	750	1200	474	115	0	0	2464	67578	59885	3420	19.68	15.55	9.19	402,071
2022	-1870	0	0	474	345	0	3000	1949	69527	61932	3420	18.83	14.85	8.86	415,462
2023	-2280	0	0	0	690	0	3750	2160	71687	63955	3420	18.42	14.59	9.05	428,649
2024	-909	0	0	0	115	0	3000	2206	73893	65870	3420	18.32	14.61	7.41	442,108
2025	-1520	0	0	0	230	0	3750	2460	76353	68458	3420	17.40	13.84	7.50	458,632
2026	0	0	0	0	575	0	2250	2825	79178	70866	3420	17.39	13.97	5.62	474,757
2027	0	0	0	0	0	0	3000	3000	82178	73320	3420	17.57	14.25	4.93	491,069
2028	-2850	0	0	0	0	0	4500	1650	83828	75606	3420	16.13	12.94	6.75	507,185
2029	-1128	0	0	0	805	0	3000	2677	86505	78066	3420	15.89	12.81	7.22	521,752
2030	0	0	0	0	575	0	2250	2825	89330	80272	3420	16.24	13.24	5.76	535,753

Table 36. Low Demand forecast sensitivity on Base Case

	Committed	Coal FBC	Import Coal	Gas CCGT	OCGT	Import Hydro	Coal PF + FGD	Total new build	Total system capacity	Peak demand (net sent-out) forecast	Demand Side Management	Reserve Margin	Reliable capacity Reserve Margin	Unserved energy	Annual energy (net sent-out) forecast
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	%	GWh	GWh
2010	640	0	0	0	0	0	0	640	44535	38587	252	16.17	16.07	459.82	257,600
2011	1009	0	0	0	0	0	0	1009	45544	39319	494	17.31	16.62	404.17	262,397
2012	1425	0	0	0	0	0	0	1425	46969	40002	809	19.84	18.16	194.38	267,783
2013	2601	0	0	0	0	0	0	2601	49570	41040	1310	24.77	21.87	41.08	274,781
2014	2543	0	0	0	0	0	0	2543	52113	41669	1966	31.26	28.92	15.46	278,876
2015	1988	0	0	0	0	0	0	1988	54101	42666	2594	35.01	30.09	10.84	285,912
2016	1355	0	0	0	0	0	0	1355	55456	43157	3007	38.12	32.43	6.37	292,717
2017	1446	0	0	0	0	0	0	1446	56902	44710	3420	37.81	31.60	5.87	299,980
2018	723	0	0	0	0	0	0	723	57625	45815	3420	35.92	29.94	2.45	308,018
2019	0	0	0	0	0	0	0	0	57625	46952	3420	32.37	26.65	3.12	316,477
2020	0	0	0	0	0	0	0	0	57625	47848	3420	29.70	24.17	3.78	323,473
2021	-75	0	0	0	0	0	0	-75	57550	48828	3420	26.74	21.41	4.31	329,526
2022	-1870	0	0	0	230	0	0	-1640	55910	49596	3420	21.08	16.01	11.34	334,562
2023	-2280	0	0	948	575	1110	0	353	56263	50299	3420	20.02	15.05	13.79	339,133
2024	-909	750	0	948	0	283	0	1072	57335	50872	3420	20.83	15.90	9.34	343,607
2025	-1520	750	600	948	0	0	0	778	58113	51903	3420	19.86	15.06	9.01	350,038
2026	0	250	0	711	0	0	0	961	59074	52737	3420	19.78	15.06	4.91	355,755
2027	0	0	600	237	0	0	0	837	59911	53550	3420	19.51	14.87	5.26	361,267
2028	-2850	0	0	474	0	0	3000	624	60535	54191	3420	19.23	14.66	6.11	366,289
2029	-1128	0	0	0	0	0	1500	372	60907	54917	3420	18.27	13.79	8.15	369,977
2030	0	0	0	0	0	0	750	750	61657	55408	3420	18.60	14.15	4.41	372,920

APPENDIX E MEASURING AND SCORING THE CRITERIA

The criteria describe the dimensions in which the optimal scenario portfolios can be assessed for “goodness of fit”. The principle is to achieve the best outcome to meet stakeholders’ objectives, no matter how much in conflict these objectives may seem.

By following a rigorous multi-criteria decision making (MCDM) approach it is possible to describe, numerate and score the preferences and values of the stakeholders with respect to each of the criteria. This provides a solid foundation to assist in choosing a single portfolio as the preferred option. In addition it is possible to identify next-best alternates that can undergo additional stress testing to incorporate concerns regarding robustness to sensitivities.

PARTIAL VALUE FUNCTIONS

Having determined the metric results for each of the potential plans a partial value function is constructed to map these results to a value representing the preferences of decision-makers. The partial value function is important in providing a precise mechanism to rank the outcomes of the different plans in a particular criterion according to the decision-maker preferences. This process should include a broad range of stakeholders to capture all the preferences.

The partial value function provides a mechanism to map the metrics for each of the criterion to a value scale that reflects the group preferences. These preferences are by nature subjective, but by including numerous stakeholders in the workshops determining these preferences a broad and inclusive approach to the values can be determined.

For each criterion the range of result metrics is determined. Taking the cost criterion for illustrative purposes, the partial value curve can be determined according to the following method. Taking two fictional scenarios portfolios, Portfolios A and B, the worst performing portfolio on this criterion is Plan A (which, on the normalised scale, scores a 1.9), whereas the best performing scenario is Plan B (which scores a 1.00). In determining the value function the worst performer scores 0, while the best performer scores 100. This range is somewhat arbitrary, it could be 0..1 or 0..5 or 0..10. The choice of 0..100 is for conceptual ease.

The next step is to determine the marginal or relative importance of different points along the curve. Determining a piece-wise linear curve with four segments a good approximation of the non-linear aspect of the value function. It is therefore simple to split the domain of 1.00 to 1.9 into four equal segments. For these segments a priority ranking is determined to indicate whether, for example, reducing the PV cost from 1.9 to 1.67 is valued more than, less than or equal to a move from 1.67 to 1.45. Once these are ranked, the highest ranking is given a score of 10, and each of the other segments given a value in relation to this score.

The purpose of this approach is the show that the relationships between the different metric results and the corresponding values are not linear. The marginal value change resulting from a change in the metric is critical to the value function.

Once the ranking is determined and a score given to each segment, the value can be calculated for each segment based on the cumulative score from the first segment to the last. If the score for the four segments is, for example, 10, 8, 6, 5, then the value for the first segment is 10/(10+8+6+5) * 100 = 34; for the second segment it is (10+8)/(10+8+6+5) * 100 = 62; for the third (10+8+6)/(10+8+6+5) * 100 = 83, and the last segment = 100.

This process should be repeated for each of the four criteria separately in order to identify preferences for each criterion.

WEIGHTINGS

A critical component of the MCDM process is to determine weightings for each of the criterion. This provides the mechanism to score the scenario portfolios across the different criteria.

In order to determine the weighting for the criteria a series of hypothetical cases are evaluated in which a portfolio scores best on each of the criteria and worst on all the others. Taking each of these hypothetical portfolios a preference ranking can be determined to indicate the extent to which one criterion is more important than others and how the other criteria relate in importance to one another. The highest priority gets an arbitrary weighting of 10 and the others are ranked in relation to the top score of 10.

Having calculated the importance weighting between the criteria and the partial value functions within each criterion a final value associated with each scenario portfolio was produced. This result is determined by multiplying the partial value result for each criterion by the weighting (as a percentage of the total weighting for all criteria).

The score from the process may indicate a preferred portfolio but this cannot be considered as the proposed IRP as the scenarios are not real-world constructs. The MCDM process may indicate a preference but the scenarios provide information to support debate on policy choices. The proposed IRP should consolidate the preferred portfolio with issues raised by the scenarios.

UNCERTAINTY FACTOR

As described in Chapter 4 each technology has inherent uncertainties relating to the assumptions made regarding future costs, lead times, operations and environmental impacts. These uncertainties and risks have not been monetised nor included in the other criteria, however a subjective factor is applied to each technology to partially account for these.

Table 37. Uncertainty or risk factor

Uncertainty in assumptions

None	Low	Moderate	High
0	1	2	3

Risks

None	Low	Moderate	High
0	1	2	3

Risk rating				
Projects	RF	Rationale	Scoring	
No risk project	0	Cost assumptions		
		Lead time assumptions		
		Security of supply risk		
		Operational risks		
Pulverised coal with FGD	7	Cost assumptions	1	Future coal costs could escalate to >R15/GJ
		Lead time assumptions	3	EIA delays, infrastructure concerns
		Security of supply risk		
		Operational risks	3	Environmental impact, water contamination, air pollution
OCGT	6	Cost assumptions	3	Future fuel costs highly uncertain
		Lead time assumptions	1	Possible EIA delays
		Security of supply risk	2	Diesel (and LNG) supply risks
		Operational risks		
Fluidised bed with FGD	6	Cost assumptions	1	Future coal costs could escalate
		Lead time assumptions	3	EIA delays, infrastructure concerns
		Security of supply risk		
		Operational risks	2	Some environmental impact, water contamination
CSP, parabolic trough	5	Cost assumptions	1	Some uncertainty regarding future capital costs
		Lead time assumptions	1	Infrastructure concerns, local capability to be tested
		Security of supply risk	1	Availability concerns (issue of capacity credit)
		Operational risks	2	Environmental impact (water)
Wind	2	Cost assumptions	1	Some uncertainty regarding future capital costs
		Lead time assumptions		
		Security of supply risk	1	Some availability concerns (capacity credit may not be correct)
		Operational risks		
Nuclear	10	Cost assumptions	3	Actual capital costs could be significantly higher than assumed
		Lead time assumptions	3	Significant EIA delays, opposition to development
		Security of supply risk	1	
		Operational risks	3	Contamination, waste management
CCGT	6	Cost assumptions	2	Uncertainty regarding future LNG costs
		Lead time assumptions	2	Uncertainty on supporting LNG infrastructure
		Security of supply risk	2	LNG supply risks
		Operational risks		
Import coal (Botswana)	8	Cost assumptions	2	Uncertain assumed costs - fuel and capital
		Lead time assumptions	1	Some infrastructure concerns

		Security of supply risk	2	Risk of neighbouring domestic need
		Operational risks	3	Environmental impact, water contamination, air pollution
Import hydro	9	Cost assumptions	3	Uncertain assumed costs - specifically infrastructure
		Lead time assumptions	3	Significant infrastructure requirements, specifically Moz
		Security of supply risk	2	Risk of neighbouring domestic need
		Operational risks	1	Environmental impact of dam
Import gas	10	Cost assumptions	3	Uncertain assumed costs
		Lead time assumptions	3	Project uncertainty
		Security of supply risk	3	Risk of neighbouring domestic need, resource supply risk
		Operational risks	1	Environmental impact of infrastructure

APPENDIX F PRICING MODEL

Extended Pricing Model Description

The pricing curves for IRP2010 has been calculated using a forward looking pricing model based upon the regulatory pricing rules as used for the MYPD2 price review of Eskom. The pricing approach complies with the Electricity Regulation Act, Act 4 of 2006, which specifies that an efficient licensee should be awarded tariffs that recover the full cost of the business, and it should include a reasonable return. See paragraph (a) in the quote below.

> **From Electricity Regulation Act, Act 4 of 2006**
>
> **Tariff principles**
>
> **16. (**I) A licence condition determined under section 15 relating to the setting or approval of prices, charges and tariffs and the regulation of revenues-
>
> *(a)* must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return;
>
> *(b)* must provide for or prescribe incentives for continued improvement of the technical and economic efficiency with which services are to be provided;
>
> *(c)* must give end users proper information regarding the costs that their consumption imposes on the licensee's business;
>
> *(d)* must avoid undue discrimination between customer categories; and
>
> *(e)* may permit the cross-subsidy of tariffs to certain classes of customers.

The pricing rules are based on a rate of return methodology, allowing the recovery of operational cost and depreciation for a financial year, with a return on the regulatory asset base (indexed with inflation) calculated using a real rate of return, currently set at 8.17% according to the MYPD2 determination of the Regulator.

The model uses the Eskom submission to the regulator, dated November 2009, as the source of data for the five year period from 2010/11 up to 2014/15. It also fixes the price increases to 25% nominal for the MYPD2 period, and then smoothly migrates to the price path based on the application of the pricing rules. Capital spending of the whole of Eskom was taken from this source, as well as all operational spending, primary energy spending, and depreciation and asset valuation. The economic variables (inflation, exchange rate) were also sourced from this Eskom submission.

To calculate the revenue requirements of Eskom the expenses were grouped into the following baskets: Employee benefits, Primary energy, Environmental levy, Other (including O&M), Depreciation, and Regulatory returns. Regulatory returns include the interest expenses, dividend payment to government if required, and tax liability. From the Rate of Return methodology, this return is a percentage of the regulatory asset base (RAB). Since the asset base is adjusted for the impact of inflation on an annual basis (the Electricity Pricing Policy of 2008 requires a replacement valuation of assets) the return percentage is a real cost of capital, and the Regulator calculated it to be 8.17% per annum. The opening balance of the RAB is also adjusted to reflect the real value of the assets, and the MYPD2 determination by the Regulator was used to obtain the asset base values for 2010, 2011 and 2012.

Annual capital spending was kept at 2015 levels up to 2019 to produce a stable long term electricity price for the Base Case. All operational spending was escalated with the long term inflation outlook of 6% per annum after 2015. The load forecast is aligned with the IRP assumptions.

The basic assumption was that the IRP Base Case aligned with the pricing model described above. This assumption allows for price comparison of all other plans and scenarios with the Base Case for the full study period from 2010 to 2030.

To simplify the calculations, the assumption was made that the MYPD2 submission for financial years could be converted to calendar years without any adjustments. This assumption could be challenged. However, the relative difference in electricity price of each plan or option compared to the Base Case price would be the important output of this exercise, thus the accuracy of the absolute price level is not a priority. Even so, the absolute price levels calculated are a good indication of where prices are heading, though not 100% accurate.

The pricing rules allow for Eskom to earn a return on Work Under Construction (WUC) and the outputs of the IRP simulations are used in the pricing model to structure capital spending according to the EPRI S-curves to reflect this pricing rule. As a result of this rule, interest during construction would not be capitalised. The difference of annual capital spending in any scenario compared with the Base Case is factored into the pricing model to reflect the impact of the plan on prices.

Capital Expenditure

The capital expenditure for each scenario is calculated using the overnight cost of each technology chosen, and the S-curve that describes the phasing of expenditure and the lead time before commissioning of each unit, as recorded in the EPRI Report titled "*Power Generation Technology Data for Integrated Resource Plan of South Africa, EPRI Member Specific Final Report, May 2010*". The capital spending is summated for all units under construction, and for all technologies chosen, to arrive at an annual real 2010 capital spending amount. This spending is then converted into a nominal rand value using the assumed inflation values per annum, and the difference with the Base Case capital spending amount is added into the model for each plan/scenario.

To ensure a more realistic termination of the price curve, the model compensates for a fall off in capital spending in the latter years of the plan when no WUC is added for new plant after the end of the study period, and the curves produced would represent a going concern past the end of the study period. After 2030 the model calculates the capital spending by calculating the amount of capacity needed to maintain a pre-selected reserve margin (15% in this case) multiplied by a rand per MW capital spending rate for the full Eskom business, estimated to be R27 000 per kW for this run. The accuracy of this technique could not be confirmed, though, and the prices in the later years should be seen as an approximation only.

Operating, Maintenance and Primary Energy Expenditure

The EPRI report is again used to determine these costs. It converts the fixed O&M, variable O&M, and fuel costs into annual expenditure by using the commissioning date of the plant and a realistic load factor determined from the IRP model output file to calculate the relevant MW and MWh figures for each technology. This is again added together to determine the annual O&M spending and primary energy spending in real 2010 rand terms. After conversion to nominal amounts, the difference in spending between a scenario and the Base Case is added into the model to produce the relevant price curve.

General Operation of Model

The model calculates the annual revenue required by the utility, using the cost baskets as described above. Using the appropriate load forecast, the revenue requirement is turned into an average selling price by dividing the annual revenue by the annual sales. The 2010 average price is the regulatory approved price, at 41.6 c/kWh. The output of the model used in the report is the 2010 rand value real average price curve from 2010 to 2030.

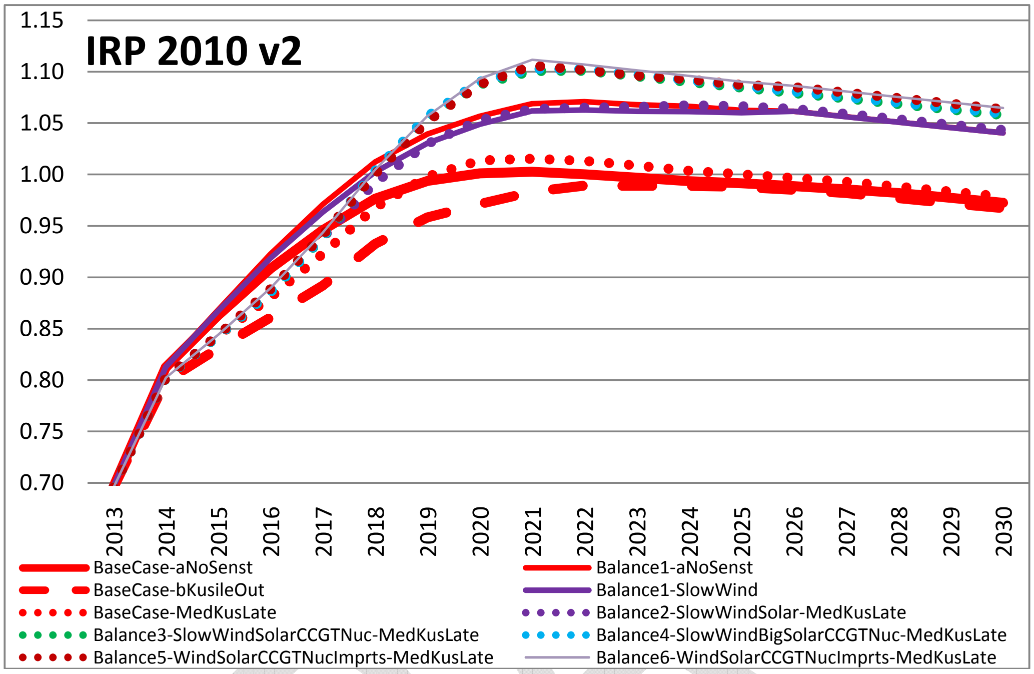
All current expenditure would be recovered in the period it is expended. The depreciation and regulatory return is supposed to compensate the utility for the capital spending, with depreciation recovering the capital cost and the returns responsible for the cost of the capital. The Base Case ends the study period with a debt: equity ratio close to 50:50 even though it starts at 65:35 in 2010 increasing to a worst ratio of 74:26 for the period 2012 to 2016, indicating that the regulatory pricing rules, if applied consistently, will be able to fund the expansion plan and the business over the long term.

To produce price curves up to 2030 it was necessary to make high level assumption regarding the capital spending past 2030. The pricing model does not, however, process any information regarding the decommissioning of existing power stations past 2030, and as a result the prices in the latter years of the study period are strictly indicative. All price curves start to show a declining trend in the later years to reflect the impact of reducing returns earned on depreciating assets, but the reality might be different for some of the plans. Caution should be exercised when interpreting the longer term pricing trends.

The model can be updated annually using the published Eskom financial statements to ensure the starting point of the calculations are sound.

RESULTS

Figure 18. Price curves for Base Case and Balanced Scenarios



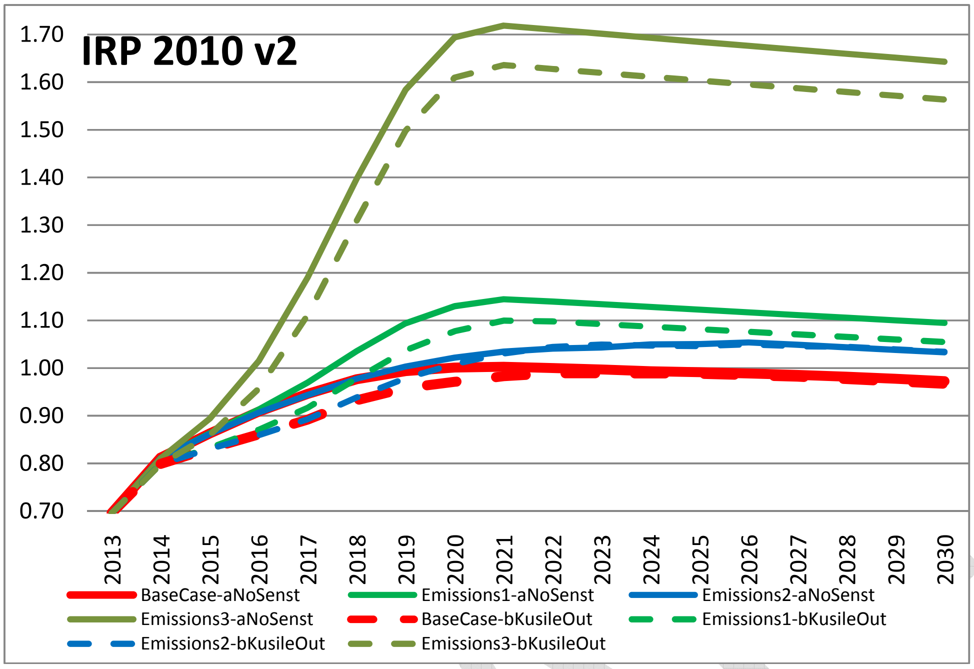
All prices are assumed to have increased by 25% p.a. (nominal increases) during the MYPD2 period, and for an additional two years at the same rate. The real price of 70 c/kWh (2010 rand value) for 2013 becomes the starting price for all price curves, increasing to just more than 80 c/kWh in 2014. From 2014 the prices follow the price curve described by the pricing rules, given the MYPD2 RAB valuation and a real return of 8.17% on the RAB value.

From the above diagram it can be seen that the Base Case then increases to a maximum real 2010 rand value price of about R1.00 per kWh in 2020. If Medupi and Kusile is commissioned later than planned for according to the current project schedule , the maximum price is slightly higher, at about R1.02 c/kWh, but it reaches this peak after remaining below the bas case price curve until completion of the delayed projects. The slightly higher price represents the cost of mitigation during the delayed construction period of Medupi and Kusile.

With Medupi on time and Kusile cancelled, the maximum price is lower, peaking at 99 c/kWh, and it reaches the peak even later. With Kusile not built, the IRP software can optimise the capacity utilisation even further, using mid merit and peaking options more efficiently to obtain the lower electricity prices. The cost of penalties to cancel Kusile would be incurred during the MYPD2 (or perhaps MYPD3) period, and since the increases are limited to 25% nominal per year, the penalty would go into the debt:equity ratio and will not directly influence the price. A penalty of R50 billion would increase the medium term debt:equity ratio from 75:25 to 85:15 when using historic asset valuation index from 2005, as was the case previously, but with the new asset valuation rules the ratio goes from 50:50 to 55:45 if a R50 billion penalty is paid, with no impact on the price curve.

The “Balance” scenarios with more focus on renewable energy in the form of wind power shows a peak price around R1.07 per kWh with Medupi and Kusile on schedule, and slightly lower at R1.06/kWh with wind introduced at a slower rate. If, however, Medupi and Kusile is delayed by one to three years, and with the inclusion of solar, CCGT and nuclear technologies with the possibility of more imports would result in slower price increases in the early years and a peak around R1.11 per kWh after 2020.

Figure 19. Price curves for Base Case and Emission control scenarios

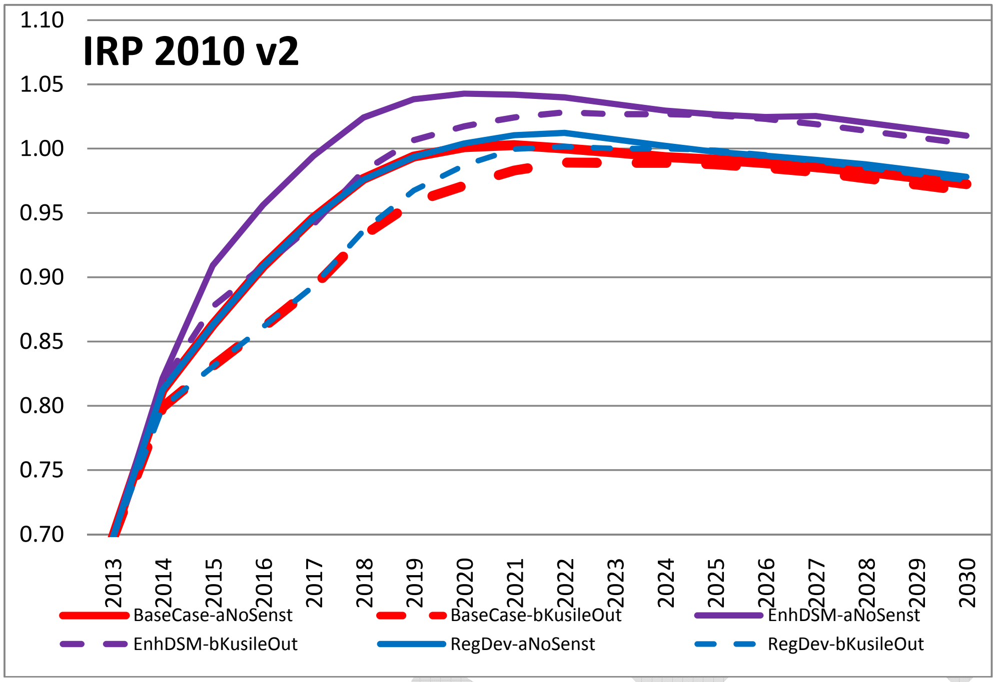


Three emission control regimes were modelled, called Emissions 1, Emissions 2 and Emissions 3. Emissions 1 limits CO_2 emissions to 275 MT per year from present time, Emissions 2 imposes the same limit only after 2025, and Emissions 3 limits the CO_2 emissions to 220 MT per year after 2020. The two scenarios, with either Medupi and Kusile constructed on time, or Medupi on time and Kusile cancelled, were evaluated.

Limiting CO_2 emissions to 275 MT per year after 2025 does not present a major price penalty over the Base Case, adding perhaps five cent per kWh to the price after 2022. Imposing this limit from today adds about 15 c/kWh to the price after 2020, due to more expensive technologies being used to supply the required load, and with Kusile built there would be a slight over capacity in coal technology, leading to under-utilised assets. The limit of 220 MT of CO_2 emissions per year after 2020 appears to be an expensive option, increasing the price of electricity by more than 70% over the Base Case.

All options with Kusile cancelled show a delayed peak price, and also a reduced peak for the tighter cases. The IRP software can optimise the peaking, mid merit and base load plant better if Kusile is cancelled, resulting in the reduced electricity prices.

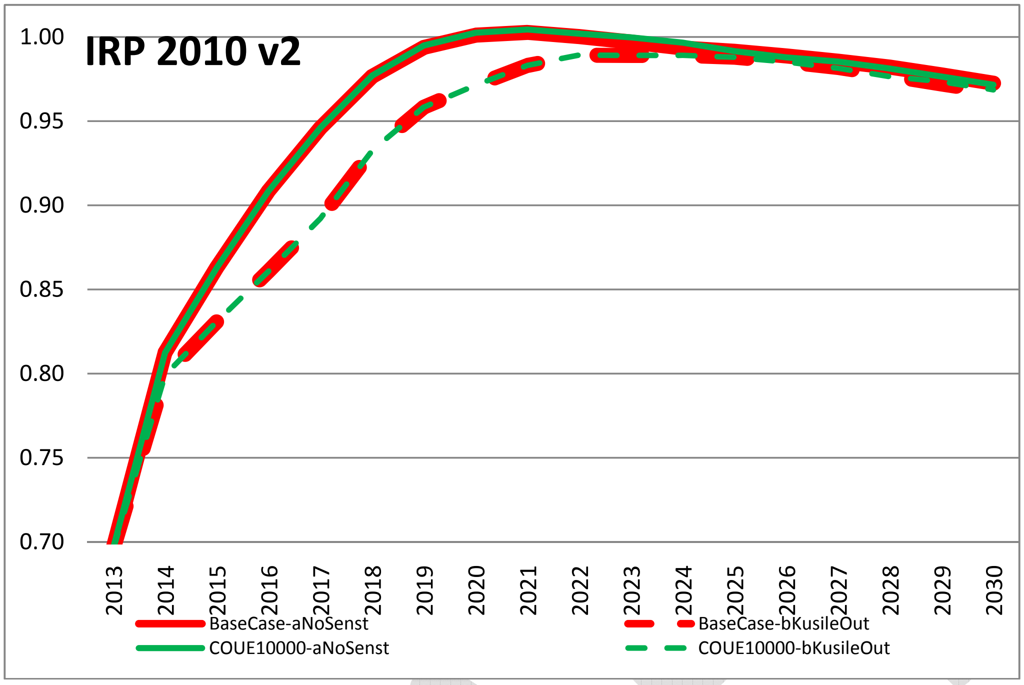
Figure 20. Price curves for Base Case and DSM/Regional development scenarios



When focussing on DSM, and assuming the additional spending on DSM techniques amount to a real R10billion per year, prices increase earlier than for the Base Case, but eventual prices would be about three to four c/kWh higher than the Base Case. DSM would cost more to implement, but has lower operating cost than generation options, and it also does not incur depreciation and returns in the books of the utility. The actual savings result per rand spent obtained could change the picture somewhat – the R10billion spent per annum is not necessarily the correct assumption.

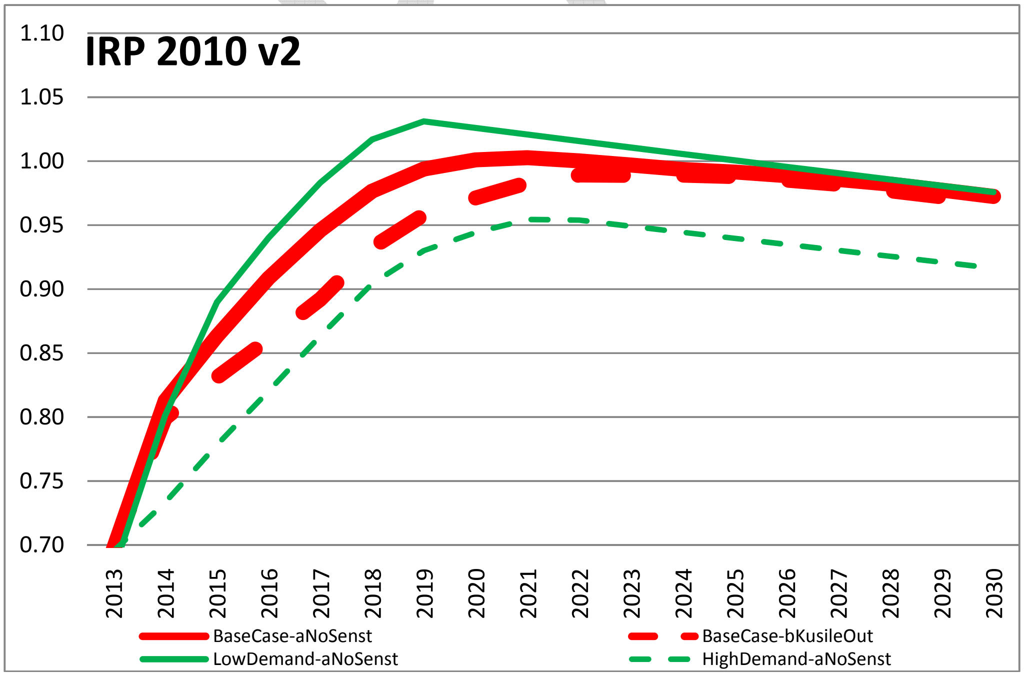
For the regional development plan, it was assumed that the cost of transmission outside South Africa would add about 15 c/kWh to the cost of the technology, and as a result the price of electricity would be around 1 c/kWh more expensive than the Base Case after 2020. The same relative margin in the price exists for both the cases where Kusile is either built or not built.

Figure 21. Price curves for Base Case and COUE sensitivity



A scenario where the Cost of Unserved Energy (COUE) was reduced from R78 per kWh to R10 per kWh resulted in almost the same price curves, with only a slight benefit in later years with Kusile in operation. If Kusile was successfully implemented, the lower COUE resulted in almost exactly the same price curve. From the IRP results it would appear that no energy demand went unserved, though.

Figure 22. Price Curves for Base Case and different load forecast sensitivities

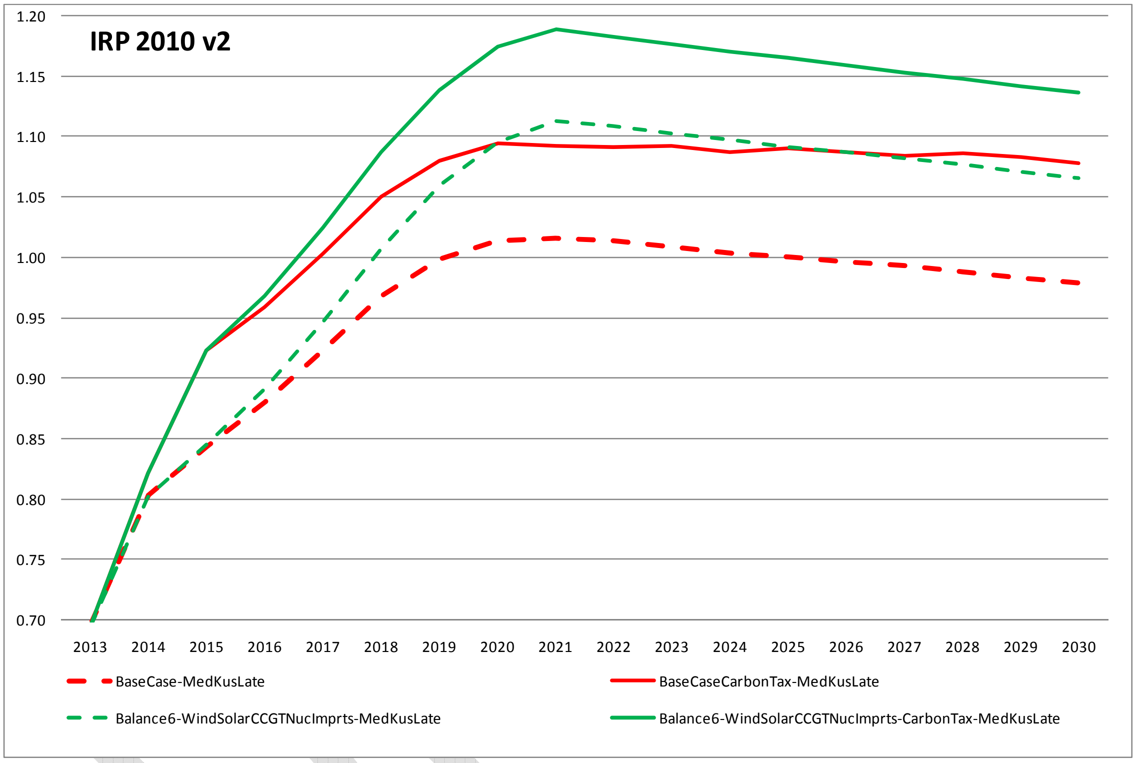


With a lower load to service, prices go up earlier than for the Base Case, with less sales to pay the same committed costs for Medupi, Kusile and Ingula. This continues as a detrimental impact on prices which peak at about 5 c/kWh than for the Base Case before narrowing to less than 2 c/kWh in the later years. Over the longer term no price premium is expected.

A higher load forecast results in prices increasing more slowly after the MYPD2 period, with more sales to pay for committed projects, and better utilisation of the assets as a result. Prices remain lower than for the Base Case for the full study period due to this better utilisation of assets.

One would expect that prices would settle at LRMC for all cases over the longer term, and the deviation for the higher load forecast case perhaps highlights the shortcomings of the pricing model at the end of the study period, where prices remain lower in this case.

Figure 23. Base Case and Revised Balance Scenario with impact of carbon tax



The inclusion of the carbon tax to each price curve indicates the impact of the tax on a scenario with greater reliance on coal-fired generation. The Revised Balanced Scenario, which starts switching to low carbon resources throughout the period and more effectively after 2022, is less impacted by the tax after 2022 than the Base Case with its high reliance on coal-fired generation. The differential between the two scenarios (including the carbon tax) at the end of the study period is much narrower than the situation without the carbon tax and is reducing.

The assumed carbon tax was R150/ton CO_2, escalating with inflation during the period. At this rate of taxation the consumer is still better off with the Base Case, but the marginal benefit reduces toward the end of the period.